

Proceedings of the Conference on Coal Use for California

Held at Pasadena, California
May 9-11, 1978

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Prepared for
U.S. Department of Energy
and
California Energy Commission
by
Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California
(JPL PUBLICATION 77-56)



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The Coal Use for California Conference was cosponsored by the Federal Department of Energy and the California Energy Resources Conservation and Development Commission. The Jet Propulsion Laboratory/California Institute of Technology organized and conducted the conference. The following JPL personnel were responsible for the conference:

Dan Schneiderman, Conference Chairman
Art Murphy, Conference Cochairman
Yukio Nakamura, Conference Coordinator

Program committee was comprised of the following individuals:

Dan Schneiderman (JPL)
Art Murphy (JPL)
Yukio Nakamura (JPL)
Don Peterson (CEC)
George Fumich (DOE)

We wish to thank the many in attendance at the conference from industry, the universities, scientific laboratories, government agencies, interest groups, and the general public.

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ABSTRACT

These proceedings contain the papers, statements, and panel session transcriptions that resulted from the Coal Use for California Conference that was held in Pasadena, California from 9 through 11 May 1978. The conference brought together approximately 400 specialists, students, interest groups and general public for the examination of technological, institutional, and social issues surrounding coal use for California and the identification of attendant constraints, impediments, advantages, and target opportunities. The expertise of the participants cover a wide range of subject matter that includes systems examination of coal opportunities, energy demand forecasting, environmental aspects of coal use, coal supply and transport, viewpoint of neighboring states, air pollution control, direct firing, coal gasification and liquefaction technologies, economics of coal use, and the regulatory system.

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OPENING SESSION

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OPENING ADDRESS

Edmund G. Brown Jr.

Governor
State of California

The future of California will be very strong with respect to energy. Today we are looking at the coal option, a very important resource. As you know, we have tried every other option and are beneficiaries of other sources such as oil, gas, nuclear and hydroelectric energy. The one source that we have not really utilized within the State's borders is coal, and no diverse energy supply would really be worthy of the name unless coal was included. There are obvious problems, but if we can put an end to our horse and buggy energy planning, look at the problem squarely, face up to the costs, and bring the varying viewpoints together, then I think we can definitely find a role for coal in generating electrical power.

The first step along that line is the meeting today. In addition, I am going to set up a Clean Fuels Coordinating Council composed of our Public Utilities Commission, Energy Commission, the Air Resources Board, the Solid Waste Management Board, the Water Quality Control Board, and our Washington representative. I am going to ask that they meet on a regular basis to quickly resolve the issues of air pollution and other environmental impacts that often follow in the wake of the generation of electric power and particularly with coal itself. I believe the obstacles can be overcome if we start to plan now if we make the hard choices, and if there is a maximum of coordination. There have been in the past separate views and sometimes separate policies adopted by these different agencies of government. Some are more independent than others, and therefore the necessity exists for bringing them together. I want the State to take the leadership role in energy.

I think that we have to construct the necessary power plants, we have to reduce the air pollution caused by electrical generation, and we have to try to hold down the costs of growth to the extent that we can. Currently in the Southern California air basin, power plants are major contributors to air pollution. In fact, more than half of the sulfur dioxide in the Los Angeles Basin is estimated to come from power plants. There is an immediate challenge that must be met. But when I see the technologies that are available, I think we can begin the design and construction of clean coal fired power plants. Our utilities have already taken a lead and we're going to work with them to resolve whatever difficulties may lie in their way.

No major construction that has environmental impact comes without resistance and this is true not just in California. If we look at Japan, we see that even trying to open an airport creates

a riot. So the mood, whether we look at Australia, Europe, Japan or even parts of this country, is one of increasing questioning of the tradeoff between the added power and its environmental impact. I think we can resolve this question if we recognize the costs and the problems early, flush them out, attack them, and overcome them.

I want to do that because this state is not slowing down. As a matter of fact, the pace is picking up. Last year about 600,000 jobs were created; that is a job creation rate 70% greater than the national average. If we look historically, there is a very close correlation between job creation and inward migration. When the job rate did not grow so fast as in 1971 to 1973, the inward migration slowed down to a trickle. As the pace of job creation picked up in 1975, 1976, and 1977, the inward migration picked up also. Given the fact that 1977 was such a big year, I would assume that 1978 will again show a rather large increase in inward migration. So we need the power. The question is how do we serve the different end uses, such as electrical use, direct heating, and direct cooling, and how do we choose from different supply options such as geothermal and more conventional sources? I don't think we can afford to ignore any of these supply options.

With respect to nuclear power, on which you have probably heard my thoughts, I would like to say that we have seven plants, at least we have authorization for seven. That being the case, I think we ought to get a few coal plants on line, to maintain diversity. We will then be in a better position to draw from whatever source has the most viability and is the most cost effective. I personally have looked at the forecast of demand as well as the cost escalation of coal, oil, and nuclear sources, and suffice it to say, there is some debate, and the range of uncertainty is rather great. I do not think that any one source can claim for itself a clear and certain cost future. Probably about all that can be derived from the data, as I understand it, is that coal and nuclear sources are competitive. One can make a strong argument that coal will be even cheaper, and I think that as the costs of decommissioning and finding adequate nuclear waste storage are brought into the picture, coal will even be more competitive. Last month *Science* magazine indicated that the waste disposal costs would be on the order of \$13 billion in today's dollars if just the plants that are already licensed are fully completed and put into operation. So the cost issue will not be resolved, but I do believe that the secure and safe energy future for California is to maximize it

diversity. The one major gap in our supply mix is coal. It is a technology that has a future. It has problems but, as far as the state government is concerned, our official policy is one of encouragement-working with the private sector, universities, and the Federal government to bring about a technology that is compatible with the quality of life here in California. That is the

reason for the Clean Fuels Coordinating Council that will work in an informal way. I came to the meeting because I wanted to listen for a while and also make sure that my administration is working as closely with you as humanly possible. Anything less than that will not bring this to an appropriate conclusion.

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WELCOMING REMARKS

Richard L. Maullin, Chairman

California Energy Resources Conservation and Development Commission

It is my pleasure to welcome both the participants and guests to the first Conference on Coal Use for California. The California Energy Commission is pleased to be a cosponsor of this exchange of facts and ideas, and our members and staff are anxious to learn from, as well as contribute to, this meeting.

To many Californians, the words coal conversion are ominous or irrelevant. They identify, however, a fundamental feature of the nation's energy program: the switch away from oil, particularly for electrical generation, and a rapid increase in the use of coal.

The words are ominous to Californians because coal burning in our state with its already exaggerated air pollution problems conjures up images of yet larger doses of smog.

Because of air pollution problems, the words may also be irrelevant. How can anyone conceive of coal conversion in California?

To remove the ominous and increase relevance to California, a national policy encouraging coal must be tailored to the requirements of the Pacific region - to its environment and its economy. Without careful tailoring of the specifics, coal conversion will join Project Independence in the junkyard of unworkable energy policy slogans.

Although we have our national energy policy in favor of coal, and it is likely to emerge from the Congress in the near future, California cannot depend on Washington's energy experts to understand and determine in detail the energy needs of this region.

In energy conservation and solar energy development, California has already enacted the measures still being debated at the national level. In other areas, such as nuclear waste management, California has provided an independent critique in hopes of focusing national attention on the solutions for critical problems.

As coal comes to California, its use will require a similar initiative on the part of California's utilities, industries, environmentalists and government. We will need policies that allow the greatest economic benefits from this

resource and that will mitigate the adverse and the unwanted costs.

Thus, our initiative must include effective coordination both between California and its neighboring coal-rich states, and between the agencies of California's government that regulate the quality of our air and water, the disposal of wastes, the supply of energy, and the economics of our gas and electric utilities.

California has no coal of its own to speak of, but the U.S. Bureau of Mines estimates that there are over 180-billion tons of coal reserves underground in the area west of Colorado.

How much of that coal will be mineable and how soon depends not only on federal coal conversion and environmental protection policies, but also on state laws and regulations on severance taxes, local enforcement of the new surface mining act, mineral rights, water rights, and so on. How much coal depends on social attitudes as well. How many boomtowns will there be, and under what conditions and controls? How should we pay for lost wildernesses or lost tranquility? How will the different states in the region share the economic benefits and the environmental burdens of coal production?

How much coal will California actually need, how much will others in the region west of Colorado need? Where should coal-fired power plants go, close to the mine or close to the coastal load centers? With modern transmission lines, it is economic in many cases to site a power plant far from the load center and near the mine mouth. But electrical generation takes more water than any other step in the coal-fuel cycle, and produces the most emissions. On the other hand, a power plant offers construction jobs in economically depressed areas.

If emphasis is placed on placing power plants near load centers, millions of tons of coal will have to be moved several hundreds of miles. If rail turns out to be the most economic mode of transport, or if restrictions on water rule out water-coal slurry pipelines, the rail systems into California will require larger investments in grade crossing improvements, track repair and maintenance

If slurry pipelines appear economical, careful attention will have to be paid to the quality of water left to flow to California through the Colorado River, as well as the obvious question of our neighboring states' water needs for agriculture and urban activity.

In some sense, the technical problems of coal use look easy when compared to the major institutional consensus needed between states, and to the coordination of federal and state policies.

Thanks in part to many who are participating in this conference, remarkable progress has been made toward the production of clean energy from coal. For example:

- (1) Emission of sulfur oxides and particulates from modern coal-fired power plants equipped with scrubbers and baghouses are as low or lower than those for oil-fired plants.
- (2) Fluidized bed boilers are now going on the market with commercial guarantees promising economic use of coal at relatively small scale.
- (3) While emissions of nitrogen oxides are still a problem, within a few years various flue gas treatments and innovative combustor designs may lower emission levels to those now achievable only with natural gas.
- (4) Designs for coal gasification combined cycle power plants promise higher efficiencies and low emissions without stack-gas cleanup, and may be fully commercial by the late 1980s.
- (5) Technical work continues on the production of clean liquid fuels from coal, which might allow an economically viable product in the 1980s.

In spite of these developments, there are enormous amounts of work to be done to realize coal's potential as a resource nationally and for California:

- (1) We need to investigate ways of handling the solid wastes inherent in coal burning and in stack gas clean systems.
- (2) We need additional work on the techniques for land reclamation after strip mining.
- (3) We need an intensified effort to improve mine safety in underground mining.
- (4) We need improvements in coal transportation and packaging.
- (5) We need to continue research on pollutants whose effects we really don't

know, and for which there are no health standards such as heavy metals and trace hydrocarbons.

- (6) Finally, we need to commercialize promising technologies with government and industry sharing the risks of first-of-a-kind ventures with important societal benefits.

Although California is not a coal-producing state, State Government, as this conference indicates, has not taken a passive role in seeking the answers to many of the questions I've just posed.

- (1) First, we have been examining where and how coal could be used with current technologies for transportation, burning, and clean-up here in California. Our first study was published exactly one year ago this month, and we have continued site and area investigations primarily in Southern and Central California.
- (2) Second, we have a study underway on the potential for industrial use of coal in California.
- (3) Third, we have initiated a joint study with the State of Utah on the role California may play as a market for Utah's coal and coal-fired electricity in a context of Utah's own needs for power and the conservation of its natural resources.
- (4) Fourth, we are pushing ahead toward the construction of the nation's first commercial scale demonstration of the integrated combined cycle coal gasification power plant.
- (5) Fifth, California has its air quality engineers up to speed on the state of the art in postcombustion clean-up systems in preparation for the advent of major coal facilities proposed for construction in California.

To those who see coal as a panacea to this state's and this nation's energy problems, I want to end these words of welcome on a cautionary note. Like nuclear power, coal alone or even in large doses will not suffice. The strength of California's energy future lies in its diversity of supply, and coal contributes to that diversity. But diversity in supply must be accompanied by increased efficiency in the end uses of energy and an accelerated effort to develop our renewable energy forms. An effective energy program for California requires all of this and nothing less.

FEDERAL DEPARTMENT OF ENERGY

COAL FOR CALIFORNIA

OVERVIEW

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Alex G. Mills

United States Department of Energy

I appreciate the sense of urgency that this particular meeting brings because we in the Nation and in California really believe that we are at a crossroads in energy policy and that what is done now is going to affect the energy activities for years ahead into the next century. Of course, the choices are not easy and within California we see every kind of energy conflict involving federal leasing, interstate electricity transmission, energy siting, water and environmental activities and all of these are in different stages of resolution. The complex system requires that in California planning consider such things as developing conventional energy such as coal, alternate energy such as geothermal, regulating energy companies, protecting the environment, and planning national, regional and state activities. Of course, I don't pretend to have all of the answers, but I do know, as Governor Brown just referred to, that, besides many energy related problems, California fortunately has many energy options which are accessible to it. It may, of course, require the adoption of many of these options, and again this was referred to. No single option is going to solve it all. As far as we in DOE are concerned, we are looking forward to participating in assisting this State so that there will be both sufficient energy for healthful life styles and reasonable growth in economy. We do hear a lot about the relative merits of soft path and hard path energy technologies. But this is as if they are mutually exclusive, and I don't believe that they are; and, in the words of Californian Bob Thorne, who last week officially became Assistant Secretary for Energy Technology, "They are mutually supportive and it is the environment or at least our concern for the environment which brings them together." Another Californian, Dale Myers, who is Undersecretary of the Department of Energy, says that, "We must use every energy option available to us to increase our domestic energy supply sensibly and to decrease our energy demand, both renewable and non-renewable, both decentralized and central; in other words, soft path, hard path." I see the fossil energy program, which I am representing for George Fumich, providing many of these options. We do research, development and demonstration on coal because coal does represent, after all, 80% of the Nation's remaining fossil fuel reserves. But the essence of the dilemma, as far as coal is concerned is not the supply but how to clear away the technical, environmental and economic roadblocks which prevent its widespread use. For this reason, I'm personally very pleased that this conference is bringing such a diverse group of people together

to consider these problems and especially so, since actually as far as California is concerned, coal is a new fuel. Perhaps, however, because of a relatively late start in California you will be able to use some of the solutions that appeared in other parts of the country where we have been operating fairly large pilot plants and designing demonstration plants. I am sure that we at DOE see many opportunities for coal utilization in California. We are developing a number of technologies and, after all, this is essentially the business of the Office of Coal Research, EEMA, and now DOE to develop technologies which are environmentally acceptable for the conversion of coal into clean gases and liquids and for clean combustion of coal. But, I would like to point out first, before mentioning some of the actual activities, the significance that we see in the Department of Energy budget. In fiscal year '79 which begins October 1 of this year, the request is for \$689 million for coal, of which \$618 million is directly for research and development of energy technology, with the additional \$71 million involved in such things as increasing basic research and on additional environmental work. One point that might be of interest; this \$689 million represents about \$1 equivalent for every ton of coal which is mined here, so it is quite appreciable.

As far as the Energy Technology Section of the Department of Energy is concerned, the budget of \$618 million for coal research represents the largest fossil energy activity, almost 85%; the others of course, being oil, shale, gas and petroleum. Now with the formation of the DOE, we have transferred from the Bureau of Mines, mining and several activities from the Environmental Protection Agency, so that our activities span mining, conversion and utilization.

Now let's look at a few of the actual programs. As far as electric power is concerned, it is quite clear, of course, that California will need additional electrical generating power plants. But coal, as I've mentioned, has really not been a primary option for California's electric utilities. However, as far as the Nation is concerned, some 45% of electricity is generated by coal and in California it represents only about 6%. Traditionally, California utilities have relied on natural gas and hydroelectricity to meet increasing energy demands, but large future additions for such plants look very remote. The Department of Energy has several major projects of potential application in California for utilizing coal to provide electricity in both an environmentally and economically satis-

factory manner. Of course, later on in this conference you will hear specific details of how these various programs are coming along. First, I would like to mention that for the direct utilization of coal there are two options: one is stack-gas cleaning and the second is fluidized bed combustion. A second group of activities concerns preparing clean burning synthetic fuels from coal; low and medium BTU gas, high BTU gas, and various liquids which incidentally include methanol. A third kind of activity are those options such as decentralized cogeneration which will provide both electricity and by-product heat at the point of need. I want to mention that a number of these projects are for the near term. Such projects actually presently involve fairly large pilot plants. For example, the 30 megawatt fluidized bed combustion plant at Rivesville, West Virginia has been operating for some time.

Of course, an additional option for the use of coal in California is to use the technology of high voltage electrical transmission lines in which electricity can be generated at a site which is environmentally and economically preferred and transferred to sites of high population density. The generation can, of course, be in-state or out-of-state. Other options which are really for the longer range future include such things as fuel cells and also magneto-hydrodynamics. Process heat in contrast to generation of electricity, has similar options which I have just mentioned and, after all, industry uses 322 of total energy in California. As I mentioned these same options which are available for generation of electricity on a smaller scale are available for the process industry.

One additional thing that might be mentioned is the steam generation for recovery of California's heavy petroleum deposits. This is something a little different. According to Todd Dozier, formerly Shell Oil's Chief Engineer, "burning of coal to make steam to produce oil is the best liquefaction process we have got." The two main enhanced oil production techniques used in California are water flooding and thermostimulation. The problem with thermostimulation is that normally a third of the oil which is produced is used to generate the heat to generate the steam and so the proposal is, that coal could be used and that this would save valuable oil. It is expected that RFP (Request for Proposal) for work on this will be issued shortly.

Now I come to synthetic fuels from coal. Almost all the technologies I have just mentioned involved the direct use of coal. A longer term alternative is synthetic liquids and gases from coals; processes such as SRC-2, solvent refined coal, Exxon Donor Solvent, and H₂ coal. These would substitute for imported oil. We are now testing these processes in fairly large pilot plants. Now I think that it is obvious that in the future, synthetic fuels will be needed; but, to do this, we need to act now to provide for the technologies that make the synthetic fuels, gases and liquids, practical in the future time. Because there are so many constraints and risks in synthetic fuels production the Federal Government feels it has a definite role in helping to create this industry. A major constraint will be that synthetic fuels production is very capital intensive and the products are more costly than their naturally occurring counterparts. So it will take cooperation between government, industry and the regulators to launch this new industry.

I must also be sure to draw to your attention, an essential part of DOE is pollution control technology. Since, of course, any environmentally unacceptable process would simply not be carried forward, we begin at the very inception of all projects to discern very carefully what the environmental factors are. When we make choices as to which project to follow forward, it is with clear concern for the environmental constraints, so that these processes, in manufacture, product, and use, have built into them technology which will minimize environmental problems. Of course, we expect that all Federal, State and Regional regulations will be met with these processes.

I do want to mention that California, as a matter of fact, is participating now in a very essential role in coal technology. Research and development to improve coal processing is carried out in a diverse range of institutions in California. In fact, we did a little count and there are 133 coal research development contracts with a total value of \$70 million in California, at the beginning of the fiscal year, with last year's expenditure of some \$26 million. Characteristically, for California these projects range from exploratory in scientific research, engineering and engineering management to special equipment development. Examples where these are carried forth are Stanford Research Institute, Jet Propulsion Laboratory and Rockwell International; as far as the engineering is concerned, C.F. Braun, Bechtel, and Fluor, and as far as equipment is concerned, and Fairchild and Consolidated Controls. Of course, many others help make up these 133 contracts.

In addition, to that, California facilities that are part of the DOE are also playing a key role, Lawrence Berkeley Laboratories, Sandia Livermore, the Department of Energy Offices in San Francisco, and the branch here in Los Angeles. In addition, I might mention that the move toward decentralization from Washington is expected to play an increasing role in transferring not only technical activities to the field, but also managerial activities. Also, I want to mention that there is a rewarding relationship which is growing within a number of important California research concerns; examples as far as petroleum is concerned are Chevron, Texaco, Union and other institutions such as the Electric Power Research Institute and, of course, a large number of universities.

In closing I want to repeat that it is our belief that there are vast undeveloped coal resources that can come to the aid of California, but to realize the potential we must be rid of the barriers. We think we are working hard and productively. Just to recall to you in sort of an overview fashion: direct combustion of coal-stack scrubbing, fluidized bed combustion, coal oil slurries, which was mentioned earlier; synthetic fuels-liquids and gases; such activities as cogeneration; long term MHD and fuel cells. I might say of all of the new things that are coming along, I think fluidized bed combustion promises to be one of the most interesting. Certainly as far as potential application is concerned, the application of coal in California for generating electricity seems to be predominant. But, for the long term, there are several other longer term activities.

This conference of course is very useful, to make us think of the barriers and how to overcome them. I hope that as far as the State is concerned you are able to hear the various activities that the Federal Government is providing as the conference goes on. I would hope also that from our

part that we're able to listen and listen closely to what the needs are in this region and in the State. In the final analysis, of course, we know that to have a coherent energy policy, it will take

cooperation between California and the Federal Government.

Thank you.

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NOTE: A written version of this presentation was not available at the time of printing. This text was prepared by the Jet Propulsion Laboratory from tape recordings of the Conference proceedings.

SESSION I

**A SYSTEMS EXAMINATION OF THE
OPPORTUNITIES OF COAL FOR CALIFORNIA**

USING COAL INSIDE CALIFORNIA FOR ELECTRIC POWER

Jack B. Moore

Southern California Edison Company
Rosemead, California

ABSTRACT

The use of coal to generate electric power is a well proven fact. The use of coal within California, however, faces a series of questions which may have to be answered before coal could be used within the state. Appropriate demonstrations, therefore, may be in order.

In a detailed analysis performed at Southern California Edison on a wide variety of technologies, the direct combustion of coal and medium BTU gas from coal were ranked just below nuclear power for future non-petroleum based electric power generation. As a result, engineering studies have been performed for demonstration projects for the direct combustion of coal and medium BTU gas from coal.

The ability to use coal to generate electric power has been well proven long before the national energy shortage was ever a serious consideration. This is due to the fact that coal is, and has been, a very inexpensive fuel for many areas of the country. Since the oil embargo and the establishment of the national goal of energy independence the utilization of coal has gained added importance - especially in areas such as California where the use of natural gas and petroleum has been widespread.

While the utilization of coal within California has received a considerable amount of publicity in the past few months, the use of coal to supply electricity to California has been taking place for a considerable period of time. Figure 1, for instance, shows the 1500 MW Mohave Generating Station located in the southern tip of Nevada -- a mere 21 miles from Needles, California. This station has been in operation since 1971 and is supplied with coal in a water slurry form by pipeline from Kaventa, Arizona, some 275 miles to the east. Other large out of state coal fired generating units are, at this very instant, producing power for us in California.

There are a number of important political and environmental issues involved with the utilization of coal within California which I understand will be the subject of other presentations at

this conference. I would like, however, to outline for you the internal planning which has led us, as an electric utility company, to the point of seriously considering coal in California and to briefly discuss a few of our proposed projects.

Of vital importance to the future of any electric utility is the establishment of a viable generation resource plan directed at selecting the type and amount of generation needed to meet projected load growth and the retirement of older, less efficient plants.

An example of the historical and forecast peak demand for the SCA system is shown in Figure 2. Notwithstanding the reductions indicated by the most recent forecast the current projection indicates that the peak demand will increase by approximately 500 MW per year over the next 20 years. Of course, one of our primary concerns is where will this new generation be sited and how will this generation be fueled?

By comparison, the planning process for answering these questions was substantially more straightforward in the past than it is today. Technological, social, economic and regulatory changes now require an almost continual, complete reevaluation of future resources and generation requirements.

In light of this rapidly changing environment and in an effort to facilitate Edison's long range fuel supply and generation resource planning, we established a special task force in 1976 to assess the company's future energy base. Specifically, the Task Force was asked to determine which potentially available conversion technologies would ensure that the company would be able to continue to provide electric energy from both existing and future generating plants. This Task Force was comprised of representatives from our System Development, Power Supply, Fuel Supply, Advanced Engineering, and Engineering and Construction Departments. The objectives of this group were threefold:

First, to develop a list of energy sources, fuel production technologies and generation methods which were not dependent on petroleum and assess their technological and commercial availability.

Second, to prepare cost estimates and environmental assessments for the more promising technologies, and finally, to prepare recommendations for the implementation of programs to develop and accelerate these technologies.

I should add that this was by no means a simple task as it involved an evaluation of the complete spectrum of energy related technologies - many of which are still in the conceptual stage. As you might expect, a certain amount of "SNAG" estimating was required to assess potential costs and environmental impacts for a number of the more advanced systems. The preliminary review identified some 41 different "technologies" which might be applied prior to 1990 and an additional 42 technologies which may be sufficiently developed to allow application after 1990.

The attention was then focused on the more immediate concern of evaluating those technologies which hold the most promise and could be expected to be available for commercialization within the next 5 to 10 years. Detailed economic and environmental assessments were prepared on these for ranking purposes. Capital and operating cost, regulatory restrictions, cooling and process water requirements, land use, transportation of fuel, and basic fuel feedstock availability were a few of the considerations used in this evaluation. The results of the economic assessment are summarized in Figure 3.

As shown, nuclear power stands as the number one choice for base load power production. This is followed by three other methods which could be available in the near term. Specifically, direct combustion of coal with advanced pollution controls, coal gasification integrated with combined cycle, and geothermal. You will note that of these three, coal gasification could serve a wider variety of needs as outlined in the objectives of this study. That is, it is non-petroleum based and it could theoretically provide clean fuel for both existing and new plants. The other two methods generally are applicable for new generation only. It should be pointed out that none of these technologies are completely without social and environmental impacts.

Based on this evaluation it was determined that we should proceed with detailed planning for a demonstration coal gasification project as well as strengthen our programs in direct coal combustion and geothermal.

One option for coal utilization that has been most recently proposed by Edison is the construction of a direct coal-fired, 1500 MW plant at an acceptable eastern California desert location. This project could be possibly brought to commercial operation in the 1987-1989 time frame, and

advanced technology for air and water quality control could theoretically be engineered into the plant. There is some concern, however, in the commitment to a project of this size since the pollution control systems required to meet projected new rules have not been demonstrated in an integrated fashion and we believe that a demonstration first on a smaller scale would be prudent.

As a result, this has led Edison to propose the option of the construction of two demonstration plants at our Coolwater Generating Station near Baggett, California.

As you know, we recently announced plans to conduct preliminary engineering studies with Ierico, Inc. to develop a 1000 tons/day coal gasification demonstration plant at Coolwater Station. We are also seriously considering the feasibility of converting one unit at this same station to direct firing with coal, coupled with advanced stack gas emission control devices.

The Demonstration Programs we presently envision will thus consist of separate Direct Coal Combustion and Coal Gasification Projects.

In the Direct Coal Combustion Project the existing 81 MW Unit 2 boiler will be retrofitted with the necessary equipment to burn coal, as indicated in Figure 4. As you might expect, the conversion of this oil-fired unit to burn coal is a sizable task. This unit, however, is one of the few on the Edison System originally designed with provisions for such a conversion, and, as a result, no major modifications to the basic boiler appear to be required. In addition to the new coal handling and combustion equipment, the unit will be equipped with a baghouse and downstream stack gas scrubbing system for removal of particulates and sulfur dioxide. Combustion modification techniques will provide the basis for NO_x control although an ammonia injection of a catalytic ammonia reduction system may also be considered. The demonstration of the ability to operate this rather complex system of control equipment will be a primary objective of the project. We believe the state-of-the-art of NO_x removal is far behind that of SO₂ and particulate removal. The extent to which this modified plant will impact the environment is an integral part of the experimental program.

An artist's rendering of the plant after the conversion to coal is shown in Figure 5. The enclosed coal handling equipment is shown in the foreground. Midway is the new stack, stack gas scrubber and bag filterhouse. The existing unit and stack are in the background.

For the Coolwater Coal Gasification

Project a two phase demonstration is planned. The basic gasification system is depicted in simplified diagram (Figure 6).

First, medium BTU gas, produced from a Texaco oxygen blown gasifier and passed through a fuel gas cleanup system, will be fired in the existing 65 MW Unit 1 boiler, to demonstrate its use as a petroleum or natural gas substitute for existing units. Emissions from the boiler as well as the gasifier will be monitored to determine the environmental impact.

In the second phase the gas will be used in a new combined cycle unit with an overall rating of approximately 90 MW. The integration of the gasifier with a combined cycle unit to achieve the lowest possible heat rate will be the primary objective of this phase of the project along with the demonstration of system flexibility, turndown capability and low overall emissions. Advanced pollution and environmental controls will be used in every step of the process from the rail coal delivery to the ultimate by-product disposal. If successful, the entire facility will serve as a model to be emulated for years to come. Figure 7 is an artist's rendering of the coal gasification plant.

The financial commitment for this program is sizable -- on the order of \$300 million for the gasification project and \$80 million for the direct coal combustion project. Because of this and the technical risks involved we are actively seeking participation from both the private and public sectors.

In conclusion, we at Southern California Edison believe that coal is the only immediate choice of a major energy source we have in light of the recent rather discouraging decisions on nuclear power for California. Since there are a series of technical, environmental, and social questions which need to be answered if coal is to be accepted, we are of the opinion that appropriate demonstrations are necessary. Thus, we believe that this program, and programs like it, are of vital importance to demonstrate that coal, an abundant resource, can serve California's future energy needs at a reasonable cost to rate payers and in an environmentally acceptable manner.

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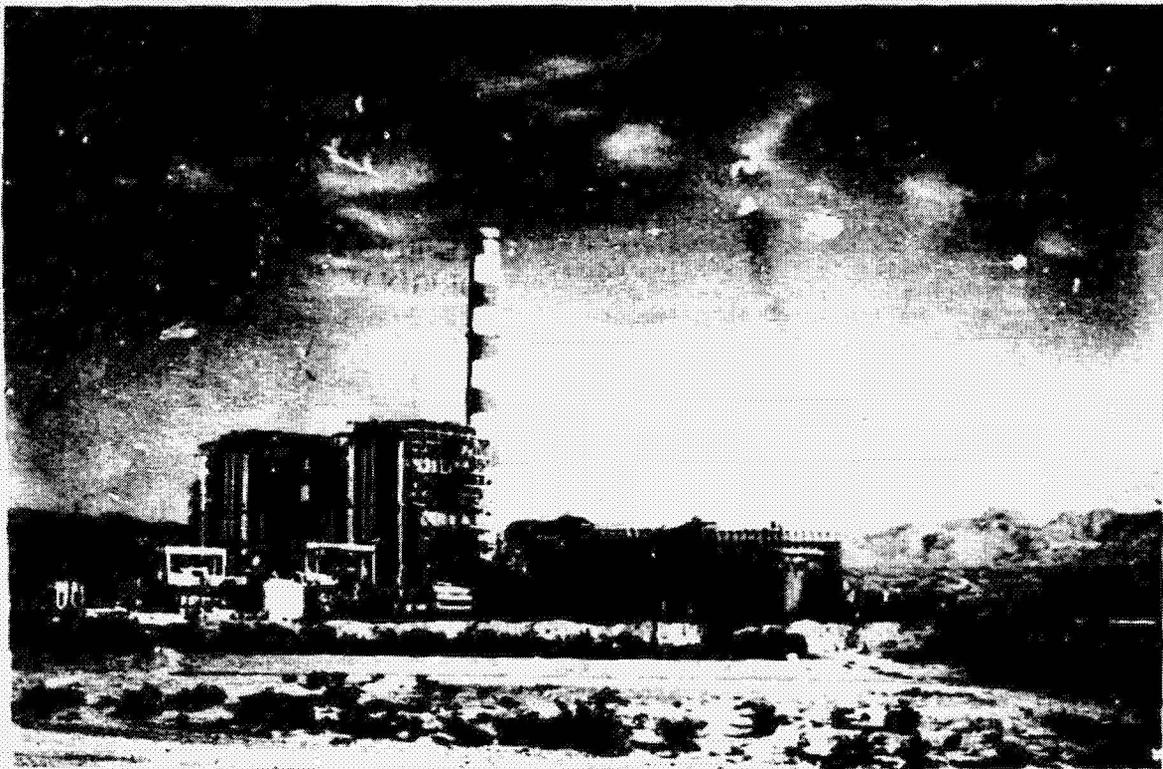


Figure 1 - Mejave Generating Station

**SOUTHERN CALIFORNIA EDISON COMPANY
PEAK DEMAND-NET MAIN SYSTEM (MW)
HISTORICAL AND FORECAST**

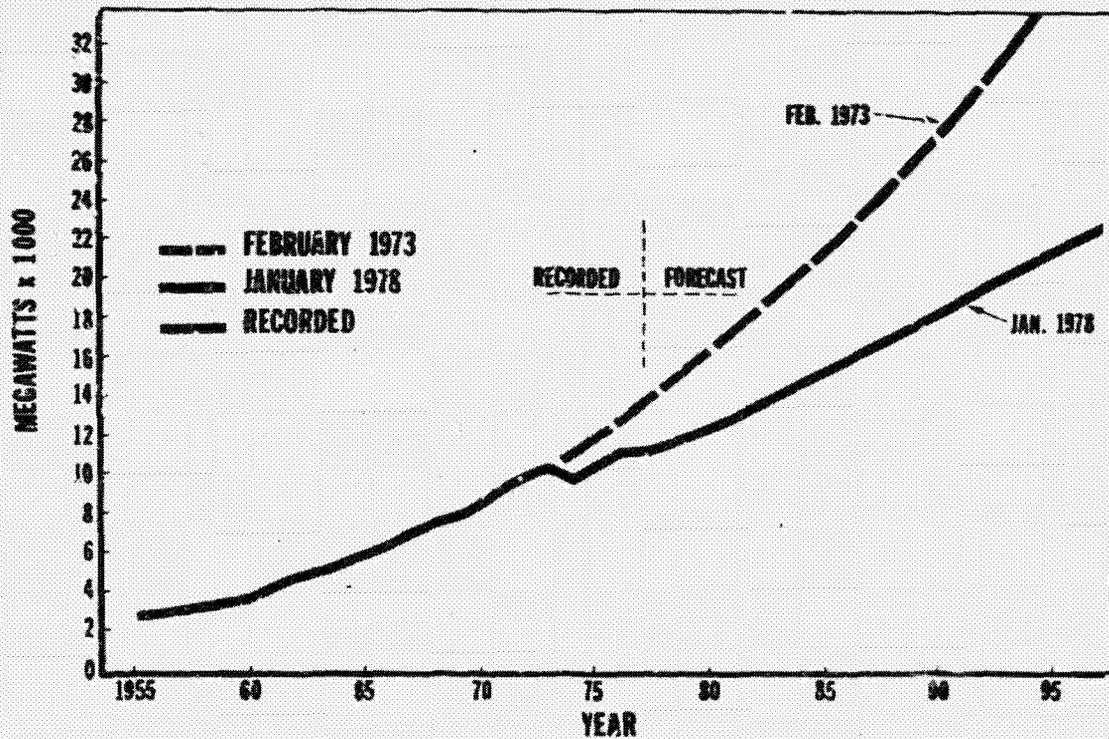


Figure 2 - Power Demand

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LIFECYCLE POWER COST ESTIMATES (1978 PRICE LEVEL)

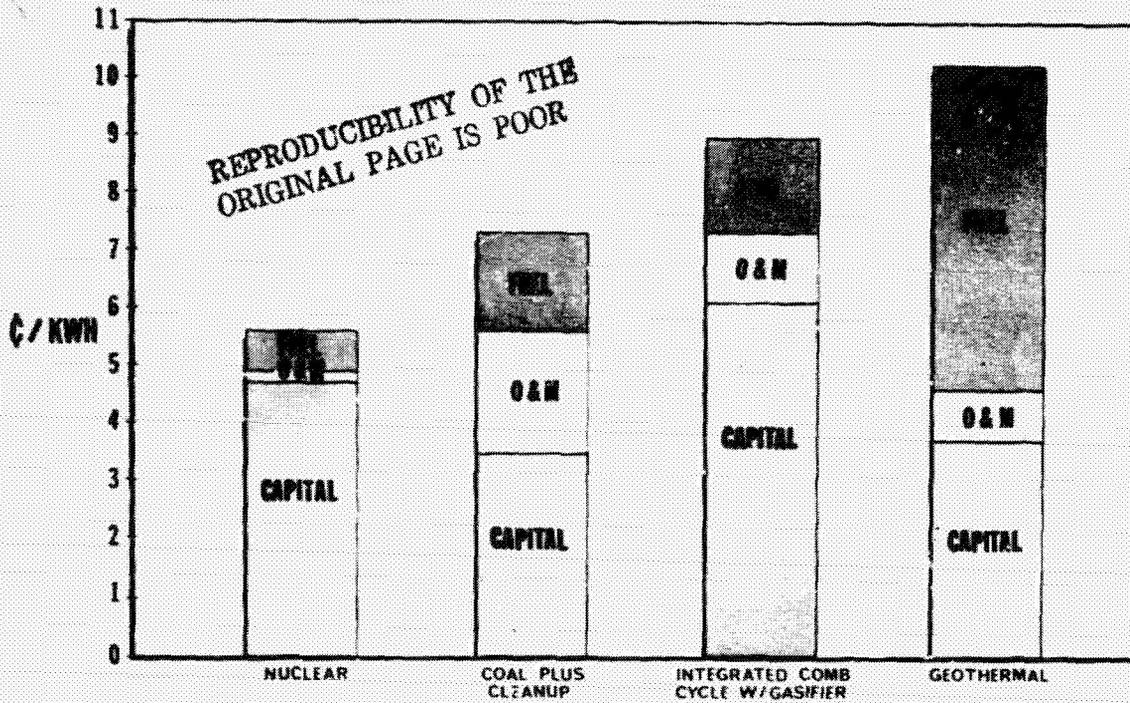


Figure 3 - Power Cost

DIRECT COAL COMBUSTION

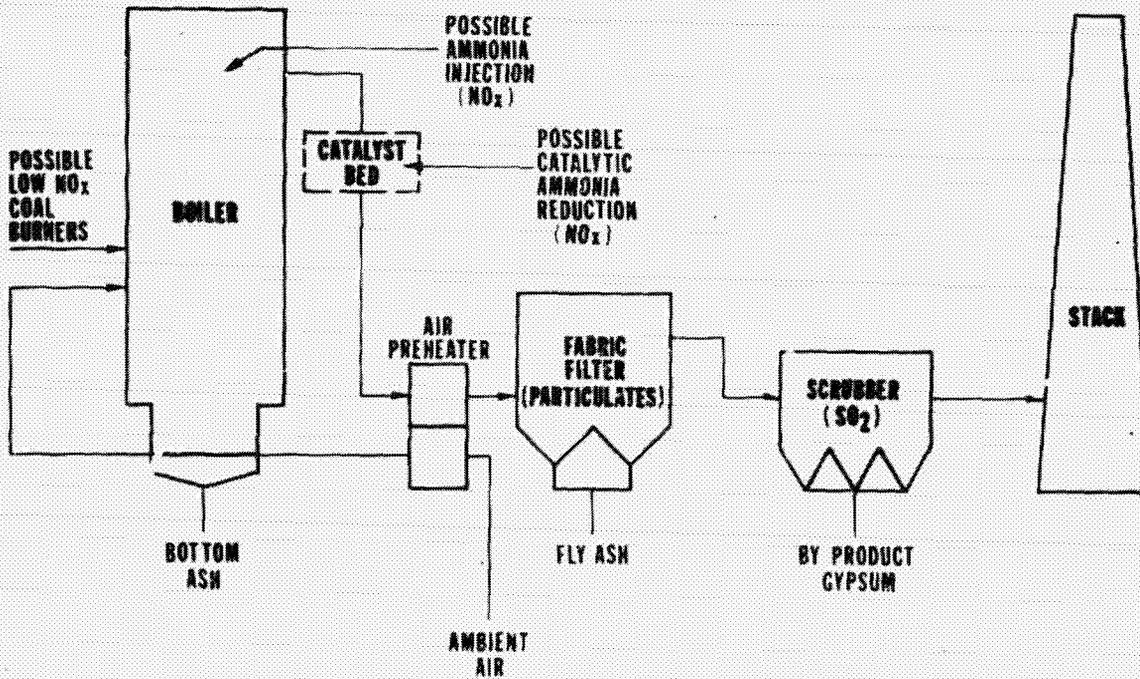


Figure 4 - Coal Combustion Pollution Controls

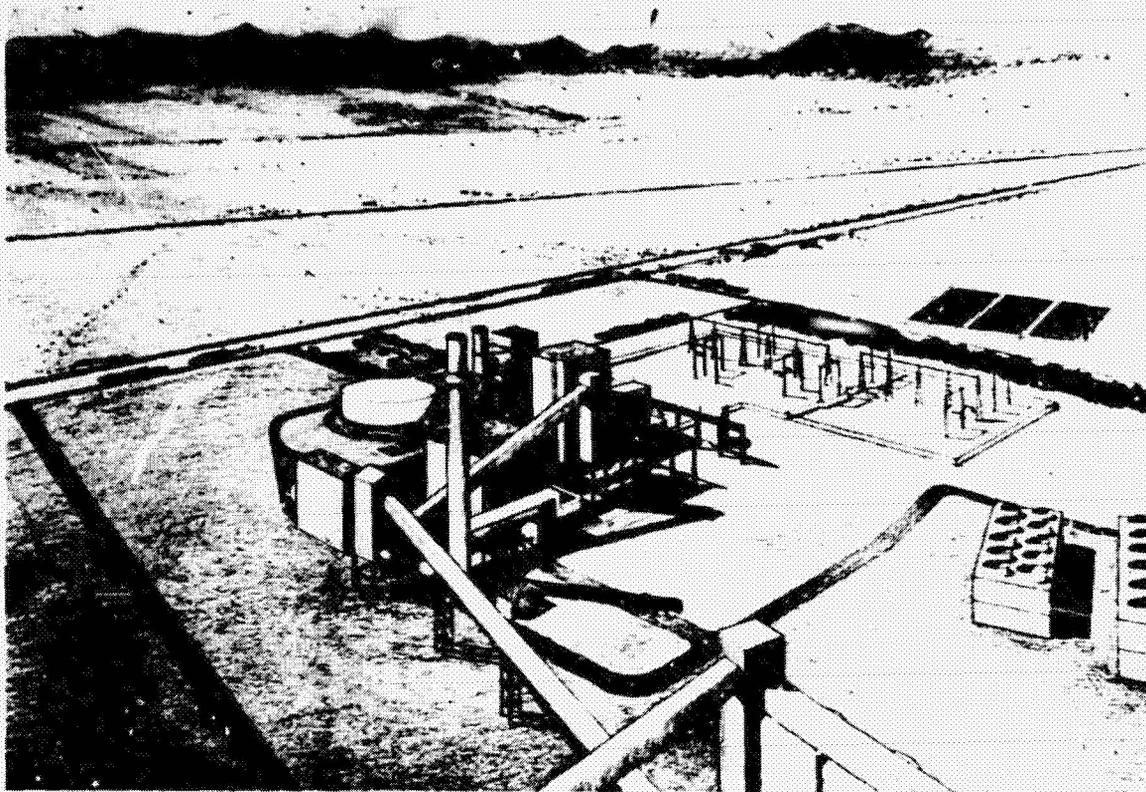


Figure 5 - Coal Combustion Artist Rendering

COAL GASIFICATION

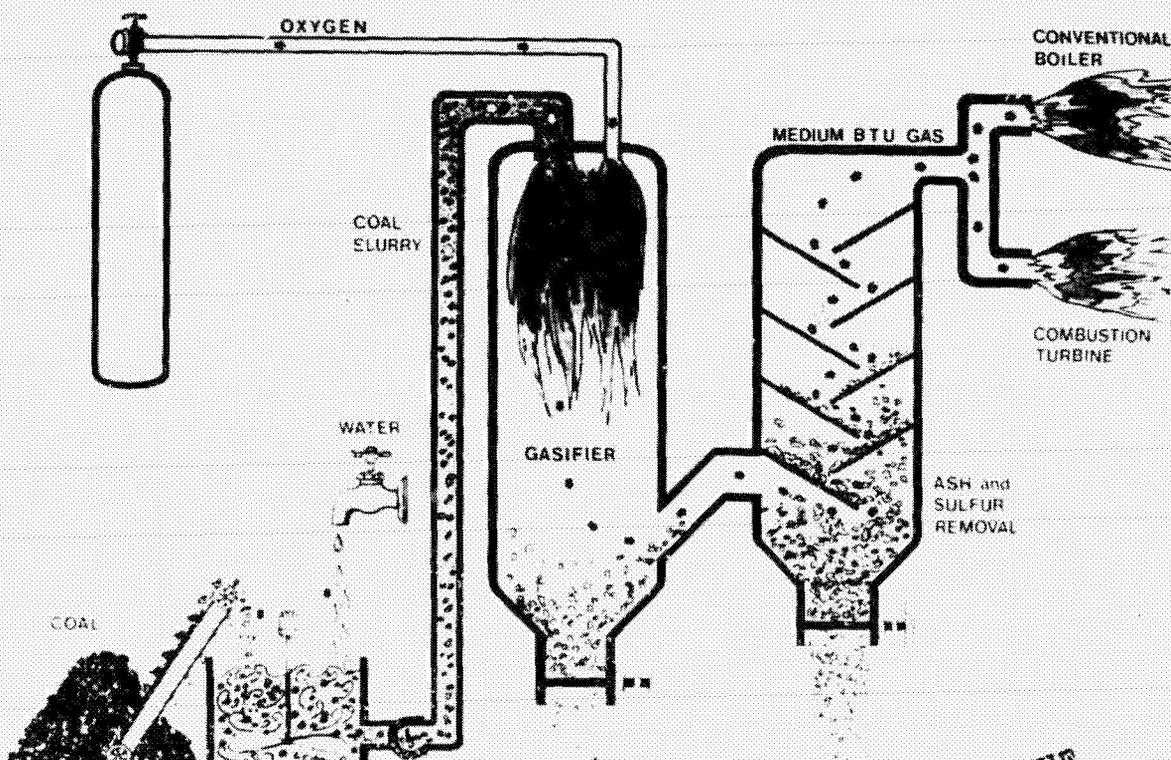


Figure 6 - Coal Gasification Process

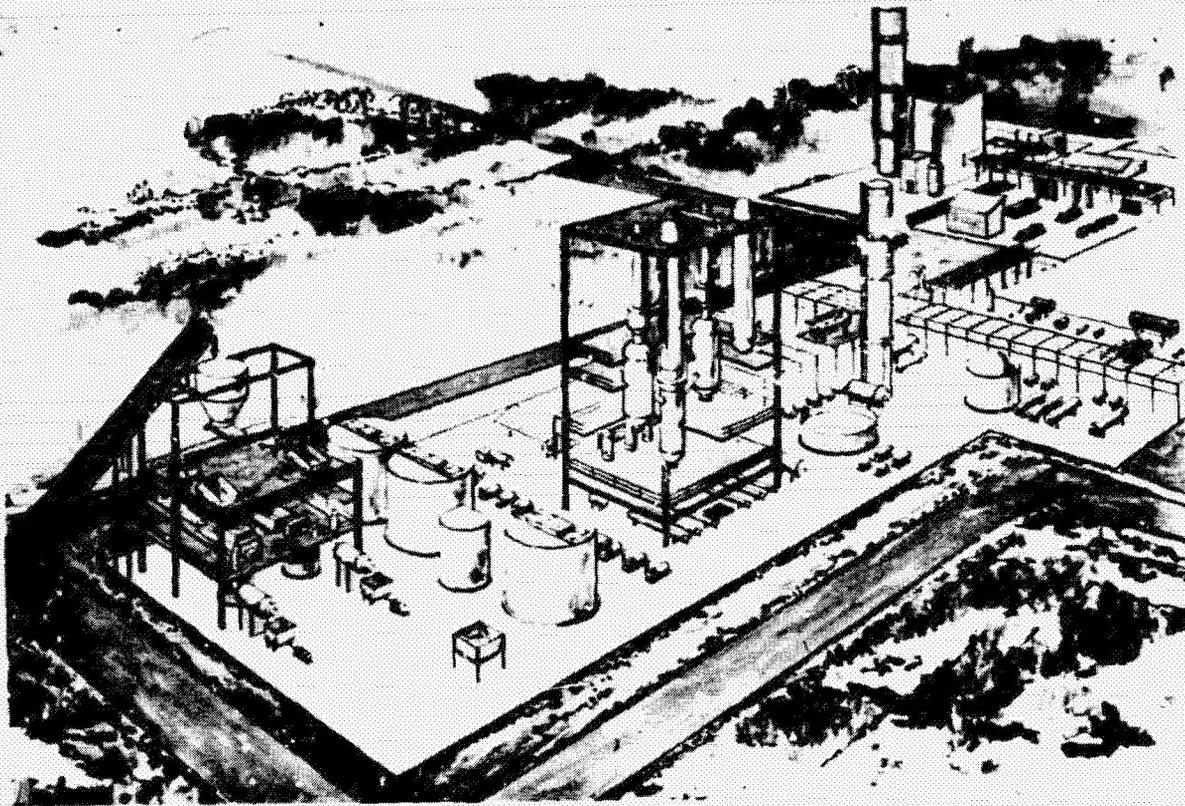


Figure 7 - Coal Gasification Artist Rendering

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**USING COAL INSIDE CALIFORNIA FOR
NONELECTRIC APPLICATIONS**

Joseph H. Oxley
Battelle's Columbus Laboratories
Columbus, Ohio

ABSTRACT

An analysis of nonelectric applications for coal will include a review of present energy consumption patterns in the manufacturing, transportation, and residential sectors. The properties of coal that affect its substitution into these market sectors will be discussed. Specific needs and concerns of Californians will be delineated. Present nonelectric consumptive uses of coal in California will be outlined. Current world-wide progress concerning increased industrial use of coal will then be shown. An overview will be given of the options to protect the environment from the direct use of coal, especially from the standpoint of sulfur control; and a time frame for commercialization will be projected. Finally, possible desired changes in energy use patterns over the next fifty years will be proposed.

ENERGY FLOW PATTERNS IN CALIFORNIA

I first would like to review the present energy flow patterns in California to put the nonelectric uses of coal into perspective. Table 1 shows the various energy delivery forms for the period July 1976 to June 1977. Petroleum is obviously the most important resource, with natural gas a close second. What may not be so well known is the fact that coal is in third place, just slightly ahead of hydroelectricity and twice the importance of nuclear. In terms of changes, nuclear increased the most last year, but coal was second in increased percentage. In terms of absolutes the use of natural gas has significantly decreased. Oil continues to dominate the scene, in fact, California increased the import of oil last year by almost 50 percent. Something else will have to happen

Table 1. Forms of energy delivery for California
July 1976 - June 1977

Energy Form	10 ¹⁵ Btu's	Annual Change
Natural Gas	1.85	-5%
Petroleum	3.88	+14%
Coal	0.15	+21%
Hydroelectricity	0.14	-38%
Nuclear	0.07	+43%
Geothermal	0.08	-9%
Total	6.18	+5%

Source: Rodman, E. D., California ERCDC.

in the future, and one of the something else may be the extensive use of coal in this state.

The users of the various energy resources shown in the first slide are highlighted in Table 2. Please notice that roughly 20 percent of the fuel consumption in California was simply to process fuel itself, i.e., 20 percent was lost for the production and processing of energy before any energy ever got to the consumer. This is also the fastest growing use of energy, i.e., wasted energy is growing four times as fast as total energy use. Fuel for transportation, perhaps not surprisingly, is the major energy benefactor, or problem, depending on one's view of society.

Table 2. Energy usage in California
July 1976 - June 1977

Energy Usage	10 ¹⁵ Btu's	Annual Change
Production and Processing	1.33	+19%
Gas H/C/A/C	1.54	-1%
Transportation	2.78	+5%
Electricity Sales	0.52	+3%
Total	6.17	+5%

Source: Rodman, E. D., California ERCDC.

if these requirements continue, then California must eventually do what the rest of the world does, and that is to use more coal. Nuclear, by itself, cannot possibly fill the gap in the near future, and there is fear that it never will. Solar will help, but unless or until we change our life style, it cannot do the job we have come to expect. We slip out of bed in the morning in an air-conditioned room to the sound of the electric alarm clock, turn on the light, flush the toilet, shower, shave, and put on nice clean clothes - all before we enter the kitchen expecting the refrigerator, stove, toaster, and so forth, to provide us with what we want. It's considerably later in the morning that we finally press the starter in our car and really start destroying the world's natural juices at a staggering rate. If we keep this up, the only natural fuel that we will have left is coal.

WHAT'S WRONG WITH COAL?

So why don't we go ahead and simply use more coal? Well, first of all, coal can be dirty.

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Table 3 shows the ultimate composition range of various coals used to generate steam in the U.S. These elements make up almost entirely the organic portion of coal, although some of the sulfur actually occurs combined with the constituents reported as ash. The ash represents the mineral matter in coal and consists mainly of silicon, aluminum, iron, and calcium oxides, along with traces of most of the other elements in the periodic table. Some of these, e.g., mercury, lead, cadmium, may be environmental problems in themselves. Moisture contents can obviously fluctuate widely depending upon mining and storage conditions.

Table 3. Composition of U.S. coals used for power production

Moisture and Ash Free:	
Carbon	69-94
Oxygen	2.2-24
Hydrogen	2.2-6.0
Sulfur	0.5-6.3
Nitrogen	0.8-2.5
As-Received:	
Moisture	1-43
Ash	3-30

Sulfur, the component of coal under most attack by environmentalists, is not thought to be normally present in the elemental state in coal, but is almost always found combined in three different types of sulfur compounds. The three types are classified as organic, pyritic, and sulfate sulfur. The organic sulfur is bonded into the cross-linked carbon-oxygen-sulfur-nitrogen chains which make up coal. It cannot be easily removed by any coal-cleaning available process today. To remove most of the organic sulfur, we must either completely gasify or liquefy the coal first, or remove it during or after combustion with a sulfur capture agent such as limestone. The pyritic and sulfate sulfur usually occur in the form of inclusions imbedded in the organic mass and are included in the generic term ash. The pyritic and sulfate sulfur can thus be quite concentrated in localized accumulations and can frequently be removed by physical techniques, and easily removed by chemical cleaning techniques.

Nitrogen is normally considered to be bound into the organic portion of coal, and upon combustion can be converted to the oxides of nitrogen which may be considerably more harmful than the oxides of sulfur. If coal is burned at high temperatures, it can also cause the "fixation" of the nitrogen in the combustion air into nitrogen oxides. Particulate emissions can occur from suspended ash particles or unburned coal, or from coal blown around during transport or handling, or from poly-aromatic organic by-products, which perhaps are the most insidious of all, and may be exceedingly harmful to health.

Despite the technical jargon in the past about producing clean fuels from coal - that's a technically difficult and expensive way to proceed. Some "cleaned coal" may be more of an environmental problem than the original coal. Fuels based on coal will not be clean unless we are willing to pay a rather considerable premium and energy penalty to cleanse them. One might argue that the real advantage in the production and use of electricity is that it is the most highly developed delivery system known today to provide clean energy from coal. The thermal and economic penalties, of course, are substantial, but many environmentalists claim we should do even more.

So that's what's wrong with coal. On the other hand, coal is stable, does not emit vapors if stored properly, is not particularly radioactive, will not leak, will last for another 200 to 400 years, and there are ample domestic supplies nearby. It has also been the principal fuel in use throughout the world since the industrial revolution. The industrial revolution demanded low-cost energy as a substitute for the energy output of human labor, and coal was the first choice. Coal also may be our last choice.

LARGE-SCALE USE OF COAL

The most energy-intensive industries in the United States at present are shown in Table 4. These industries command approximately three-fourths of all the energy used in manufacturing. They therefore represent the primary opportunities for the expanded use of coal. Since they use lots of fuel and electricity, they are also targeted industries for cogeneration of more on-site electricity and process heat. I would like to discuss each of these industries from the standpoint of coal use.

The chemical industry can, and in some places does, use coal for process heat needs now. Kerr-McGee Corporation, for instance, has a coal-fired boiler for process steam at Trona. The chemical industry will probably eventually shift back toward the use of coal as a feedstock as well. This may not be as difficult as one might think at first glance. Until the advent of cheap petroleum, the world's organic chemical industry was originally based almost entirely on the pyrolysis of coal, as it is still practiced today in the coke ovens of steel plants. However, the price of these organic chemicals will rise if we institute the widespread use of a less convenient raw materials such as coal for petroleum as a feedstock. This is another one of those difficult choices. If we want to continue to use our natural petroleum liquids to fuel our automobiles, then we will force up the cost of organic chemical products now made from petroleum, such as plastic dinnerware, rugs and carpets, blankets, clothing, automobile components, and now even most of our furniture, to noncompetitive price levels from a world standpoint. These chemical products will

be increasingly produced at lower cost in the Middle East, with subsequent continued erosion of United States jobs, and even worse balance of payments problems.

Table 4. The six largest industrial users of energy

Industry	Percentage of Total Industrial Purchased Energy		
	Purch. Fuels	Purch. Elec.	Total Energy
Chemicals and Allied Products	21.5	19.4	20.8
Primary Metals Industries	17.9	23.8	19.8
Petroleum and Coal Products	13.3	4.6	10.5
Paper and Allied Products	10.5	7.8	9.3
Stone, Clay, and Glass Products	10.8	4.8	8.8
Food and Kindred Products	8.0	6.9	7.7

Source: NASA-JPL, Technology Briefing on Cogeneration, Washington, D.C., September 15-16, 1977.

The alternative to pyrolysis or direct liquefaction of coal is the gasification of coal and then reforming, as desired, to the products as shown in Figure 1. If we want to pay the price, we can produce low-Btu or intermediate-Btu gas (sometimes called fuel gas) for our industrial furnaces, high-Btu gas (also called synthetic natural gas) for our homes, ammonia as fertilizer for our farms, chemicals for plastics, and methanol for relatively small energy uses such as irrigation pumps and turbines. These will not be cheap products, however. Coal competes with oil and gas on a Btu-basis for direct combustion. If we now convert coal into a gas or liquid by a relatively complicated chemical process, the cost of the synthetic product is probably going to be more than that of natural petroleum-based material it is designed to replace.

If we reexamine Table 4 concerning industrial energy users, the paper industry, which uses wood almost exclusively as its raw material, and is the fourth largest industrial user of energy, could obviously use coal for energy, as it does in many states already. However, this might be unwise in the long run. Perhaps the paper industry should simply be encouraged to use no other fuel than wood itself. It certainly is in a better position than anybody else to use wood, a fuel which we are trying to encourage others to use.

The food products industry in California has substantial needs for fuel. The problem with the use of coal here is the seasonal nature of the demand. If the costs of environmental control technology must be written off over a relatively small fraction of the year, the use of coal may prove to be uncomfortably expensive. The food industry therefore represents a potential market for the so-called cleaned coal, or solvent-refined coal, if regulations could be judiciously written to permit the intelligent use of this technology. Whenever possible, of course, the wastes from these agricultural operations should be used for fuel.

Perhaps the most immediate substitution possibility is the use of coal in the petroleum industry. Figure 2 shows a photograph of a Union Oil steam-flooding operation at Guadalupe. These units generate steam by the combustion of oil, the steam is then injected into the ground to force up additional oil. The flue gas from the boiler is scrubbed with caustic. Perhaps surprising to many of you, California has more SO₂ scrubbers in use than any other state in the nation. That should bring a smile of satisfaction from Frank Princiotta. A close-up of a Chevron steam generator at the Kern River reservoir near Bakersfield is shown in Figure 3. The oil furnace is the horizontal cylindrical device, and the caustic scrubber is the vertical box-like structure between the boiler and the flue. Coal could be substituted here for steam generation to save more oil for our automobiles, but more manpower would be required to operate the units, and then there is the problem and cost of ash disposal. The cost of gasoline would therefore rise, but perhaps that's good, and certainly the oil reservoir would last a little longer, which is what we are trying to accomplish from both a national and a state standpoint.

The last two of these six most energy-intensive industries already use substantial amounts of coal in California. The Kaiser Steel Mill at Fontana now consumes 7000 to 8000 tons of coal per day. The coal is brought in by train from the Sunnyside mine in Utah and the York Canyon mine in New Mexico. The underground mine at Sunnyside is shown in Figure 4. The coal is brought to the surface and transferred to unit trains. You will hear more about these unit train shipments later in the program. The coal is charged to coke ovens like that shown in Figure 5. This is a photograph of a slot oven. The coal is ground, mixed, and rammed into the open slot, allowed to cook or stew to drive out the volatile by-products and to cement the residual coke into massive chunks suitable for charging to the blast furnace. In the blast furnace, iron ore is reduced to molten iron, at extremely high temperatures by the coke. A photograph of the molten iron running out of the bottom of the blast furnace at the Fontana works is shown in Figure 6. From here, the iron is refined to steel to be used as the raw material for numerous

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products, the most important of which is our friend the automobile, but also for cans for food processing, supports for our buildings, and conduits to bring water, gas, electricity, and coal into our homes. Steel is also used as structural components in bridges and highways, which are again needed by our faithful automobile.

The other significant industrial use of coal at present in California is in the cement industry. A photograph of the Amcord cement plant just outside Riverside is shown in Figure 7. The five long tube-like affairs at the upper right are the coal-fired rotary kilns. The coal pile at center left is shown in close-up in Figure 8. The natural deposit of limestone, also used in the production of cement, is the natural mound of material sticking up behind the coal pile. Coal is pulverized and fed to the kilns to supply the heat necessary to produce the cement. The ash and sulfur can be incorporated with the limestone into the cement, which solves most of the pollution problem. Figure 9 shows a close-up of the baghouse which filters the effluent gases from the kiln. As may be noted, baghouses do a very effective job of removing fly ash and kiln dust. One of the principal uses of cement is in roads for automobiles.

SMALL-SCALE USES OF COAL

Since there is very little use of coal for heating, cooling, and air conditioning applications in California, I am going to use some slides showing photographs of the use of coal in Ohio for illustrative purposes.

Battelle provides research services for roughly 2500 people in Columbus, Ohio, and our power plant is shown in Figure 10. We have three boilers, one of which was converted to coal two years ago. Our coal pile is shown to the right. The feed hopper is the tall, vertical, cylindrical, cement block structure on the left. These boilers help to supply heating in the winter and cooling in summer, as well as process steam to operate our experimental equipment, and the like, throughout the year. During the gas shortage of two years ago, when the entire school system in Ohio was shut down for three weeks because of lack of gas, we opened our doors to approximately 2000 school children in Columbus so that educational programs could be continued in our facilities. We felt quite secure with our coal pile. We also use coal-generated steam to run our 90-ton/hr chiller, which cools our 600-seat auditorium. This chiller is based on a lithium bromide cooling cycle, which employs steam for regeneration.

There is at least one facility in Ohio which uses a scrubber on the power plant, and a photograph of such a unit on a nearby air force base is shown in Figure 11. Sludge disposal is a problem here and the technique used for sludge disposal is simple impoundment. A view of the 2 1/2 acre pond is shown in the foreground. This pond has sufficient

volume to store the sludge which will be accumulated during the next five to ten years. After that, presumably we will have to dig another pond.

I would now like to show a photograph of a house in my neighborhood which still employs a coal-fired stoker in the basement for heating in the fall, winter, and spring. A view of the house from the front is shown to the left in Figure 12. The previous night the temperature dropped down to about 32°F, and the furnace was on when this photograph was taken. No emissions from the chimney could be observed. A view inside the basement is shown in Figure 13, and you will notice a nice warm fire in the hearth. The ashes and clinkers must be withdrawn periodically, and the tubs containing previous withdrawals, waiting to be carried out, are shown on the floor in front of the furnace. The last photograph in this series, Figure 14, shows the coal bin and clean clothes hanging in storage to the right of the coal bin. A much cleaner arrangement than my own basement, which contains a coal fired furnace that was converted to gas several decades ago.

THE FUTURE OF COAL IN CALIFORNIA

Coal should be used in California with discretion. The larger the boiler or industrial furnace, the more attractive its use will become. Coal should probably have first priority for the process needs, and especially the high-temperature process needs of industry. Its use in smaller scale applications such as for space heating and cooling in residential, military, hospital, commercial, or light industrial complexes should be accelerated.

Research work going on in California which may be of help in the future is shown in the next two figures. Figure 15 is a view of the TRW Capistrano pilot plant on a new process to clean coal. As indicated earlier, however, if the coal contains large amounts of organic sulfur, it cannot be of great help. Figure 16 shows a view of the Weyerhaeuser 7-1/2-foot diameter fluidized-bed combustor and its associated 1-MW gas turbine located at the Combustion Power Company's Menlo Park facility. The fluidized bed shows promise as an alternative to flue gas desulfurization in that it will capture sulfur during combustion, hopefully at lower cost. Other pertinent work is going on right here at JPL, by Occidental, Stanford Research Institute, and many other organizations.

However, the massive socioeconomic change which is facing not only Californians, but the nation, as well as most of the world, is the problem of the automobile. In terms of the long-range future, it seems that the transportation system based on the personal automobile(s), as we have come to know it, will have to change.

Electricity may be the preferred source of power in the future for most personal transportation, including the automobile, the light truck, the railroads, and mass transportation. This electricity could be produced primarily from coal in large, relatively efficient plants. Cleaned coal, or the so-called clean fuels from coal, could then be used for individual residences and for light manufacturing. Heavy industry will continue to use coal as it has in the past. I am sorry to report that energy for all such uses will no longer be cheap. If the federal government wants to force the technology of synthetic fuel from coal into the industrial marketplace, I believe the most expedient route to do so would be for the government to become the purchaser of such fuels, and to use such synthetic fuel for governmental purposes. The state governments could then join in such federal endeavors as they think prudent.

We must decide for ourselves, and decide relatively soon, what price and sacrifices we are willing to accept for the continued exploitation of energy. Coal should be utilized where appropriate, but it should only be used with discretion. It cannot be both clean and cheap, no matter how much we want it to be otherwise.

ACKNOWLEDGMENTS

I would like to acknowledge the help of Dr. Don Peterson with the California Energy Commission for background information on California's energy needs. Help with respect to visual material was provided by Dr. Shirley Wigton of Weyerhaeuser and Dr. Bob Meyers of TRW concerning photographs of their pilot plants in California; by Harvey Rosenberg of Battelle for the photographs of the scrubbers at Rickenbacker, Bakersfield, and Guadalupe; and by Dave Ball of Battelle for the photographs of the baghouse and coal pile at the cement plant in Riverside. The aerial photographs of the Armcord cement plant, and all photographs of the operations associated with the Fontana Steel Works were reproduced from annual reports of the Kaiser Steel Corporation and Armcord, Inc. Finally, I would also like to thank our neighbors, Mr. and Mrs. John S. Motil, for permission to photograph their lovely home.

<u>Process</u>	<u>Product</u>
Air Blown Producer	Low-Btu Fuel Gas
Oxygen Blown Producer	Medium-Btu Fuel Gas
Methanation	Synthetic Natural Gas
Haber	Ammonia Fertilizer
Fischer-Tropsch	Olefins and Paraffins
Oxo-type	Alcohols and Aldehyde

Fig. 1. Chemical products by the gasification of coal



Fig. 2. Union Oil steam flooding operation at Guadalupe



Fig. 3. Chevron steam generator with scrubber near Bakersfield

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Fig. 4. Photograph of Longwall mining operation at Sunnyside

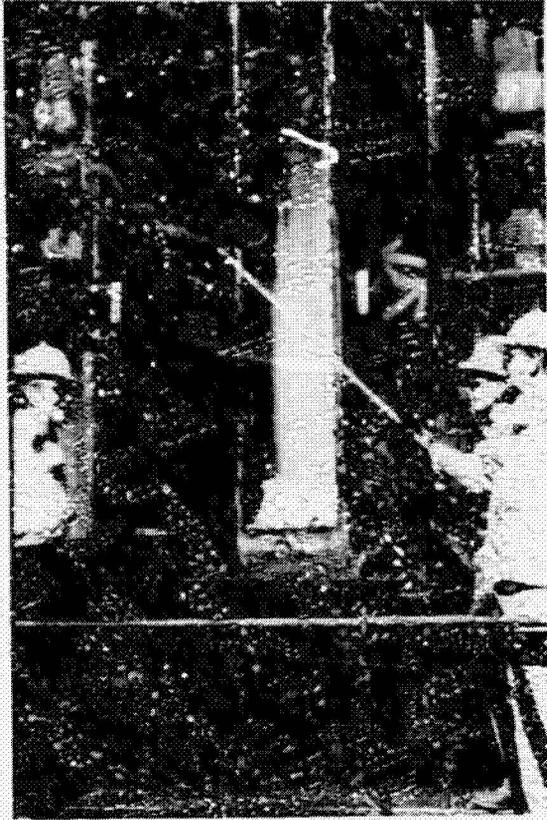


Fig. 5. Slot ovens for coke production at Fontana

Fig. 6. Discharge of molten iron from the blast furnace



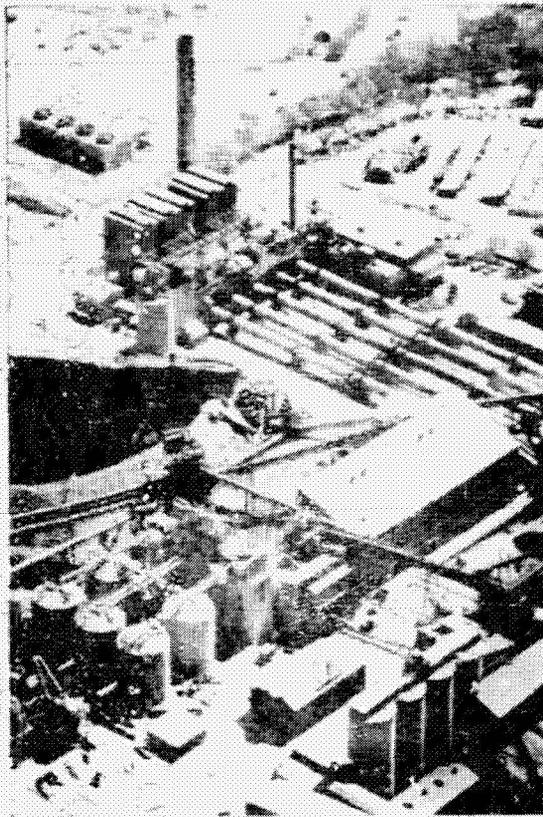


Fig. 7. Ancord cement plant
at Riverside

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Fig. 8. Storage pile for coal for cement production

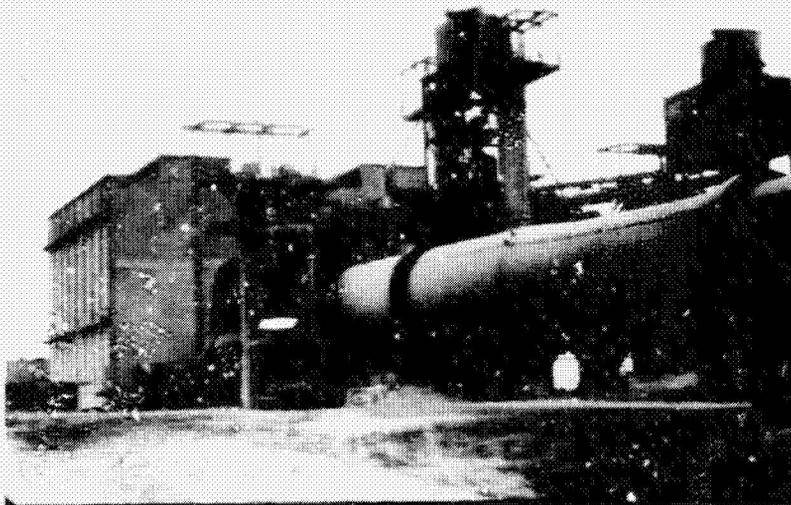


Fig. 9. Baghouse for dust control
at Amcord plant

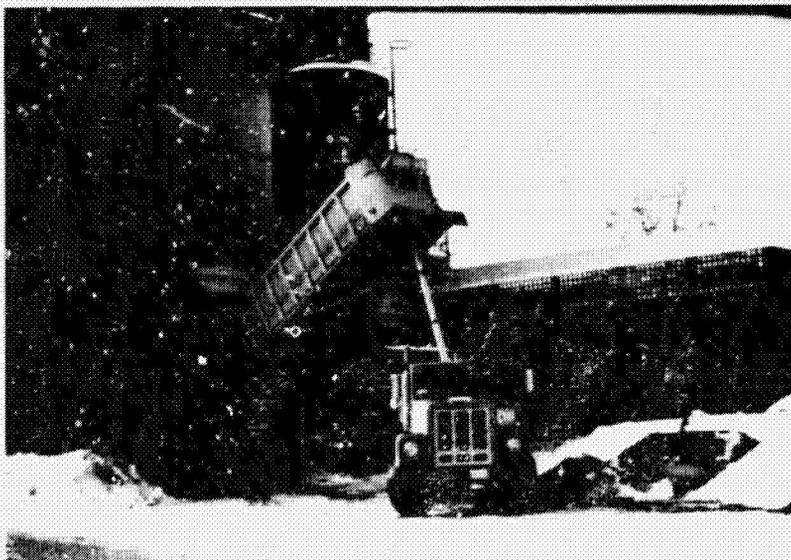


Fig. 10. Power plant at Battelle-Co'umbus

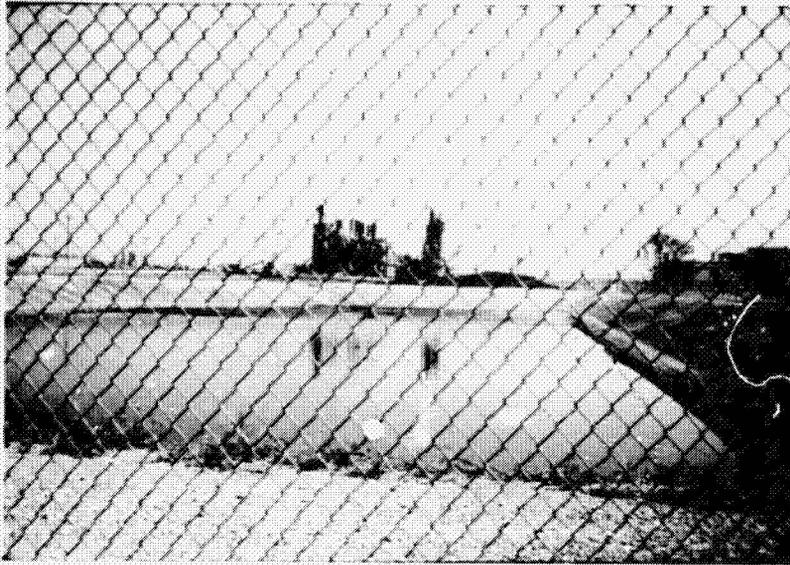


Fig. 11. Sludge pond for scrubber at Rickenbacher Air Force Base

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Fig. 12. Photograph of home with coal-fired furnace

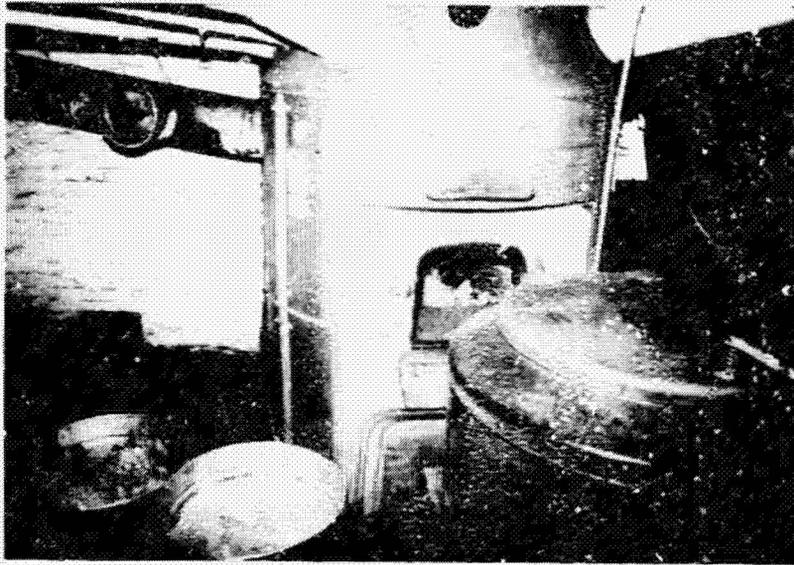


Fig. 13. Stoker furnace in neighborhood basement



Fig. 14. Storage areas for coal and clean clothes



Fig. 15. TRW pilot plant for coal cleaning at Capistrano

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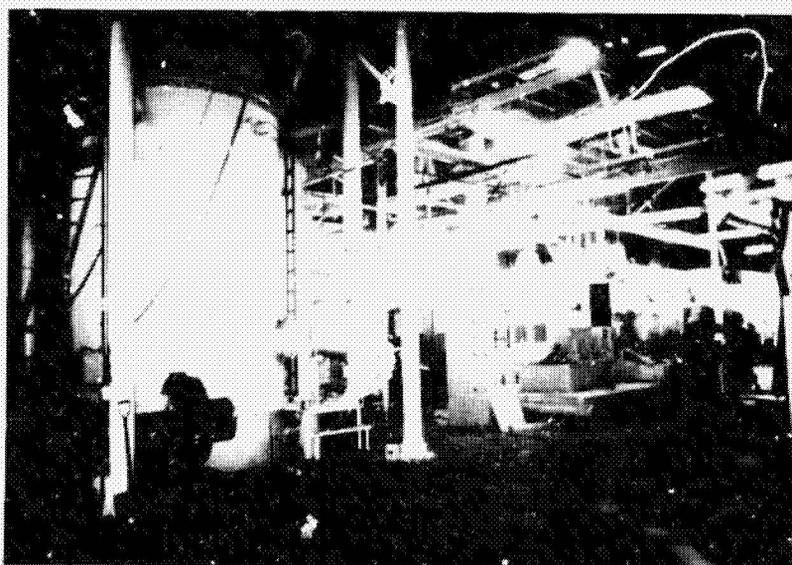


Fig. 16. Weyerhaeuser's fluidized bed combustor at Menlo Park

A SYSTEM EXAMINATION OF THE OPPORTUNITIES OF COAL FOR CALIFORNIA

M. H. Hathaway

Fluor Engineers and Constructors, Inc.
Irvine, California

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ABSTRACT

Appreciable empirical evidence has been published which indicates a strong correlation between a society's economic wealth (its GNP) and its energy consumption. With a growing population and increasing individuals' aspirations, California's energy demands will also rise in the future.

Because of decreasing availability of petroleum fuels and natural gas, it is imperative that alternative means be developed for meeting these demands. In this paper we examine the options available for importing energy derived from coal.

These include: (1) electric power generated from coal, (2) coal gasification near the mine site for conversion to substitute natural gas or liquid products such as methanol or hydrocarbons, (3) converting the coal directly to liquid hydrocarbons similar to a synthetic crude oil.

Comment is made on the long lead times required between conception and completion of facilities of this type. Because of political and economic impediments, excessive delays have resulted in cancellation of projects such as Kaiparowits and WESCO.

The need for statesmen and citizens with vision and courage to act is emphasized.

Importation of Coal-Generated Energy;
An Examination of Options

I. INTRODUCTION

The title of this session, referring to opportunities of coal for California, is one of the most encouraging signs I've seen to signify that more than just a few of us recognize two key facts:

- (1) At some point in the future, we in California, along with all other Americans, will not be able to get as much petroleum products or natural gas as we'd like to get for the kind of price we'd be able or willing to pay.
- (2) America's vast reserves of coal offer the hope of supplementing our energy needs at prices we can afford.

I've been asked this morning to examine just the options of importing coal-generated energy into California. The other two speakers of this session have addressed the problems associated with bringing in the coal itself for use here. Among us, we

raise the kind of questions and issues which most people feel are important.

Since we've implicitly accepted the idea that an energy crunch is looming, there doesn't seem to me to be a need for documenting the why's and wherefore's of it. It does seem appropriate, however, to comment on the impact on our economic or material well-being that we should expect if our energy supplies do become inadequate.

Appreciable empirical evidence has been published which indicates a strong correlation between a society's energy consumption and its economic productivity, measured as GNP per capita. Among the leading industrial nations of the world, the U.S. compares favorably as an efficient user of energy as measured by GNP/Unit of energy consumed. Some countries with outstanding energy consumption records usually have small populations and produce fine products; for example, Switzerland derives appreciable income from low energy content exports of fine clockworks.

There are fewer than 30 countries in the world with populations larger than California's 22 million; there are only 51 countries in the world with areas larger than her 160,000 square miles. If we were a separate country, our GNP of some \$150 billion would be about the 7th or 8th largest in the world. This tells me that our state is big enough that the general data will apply to us. So I conclude that our economic well-being bears a strong relationship with our energy consumption. This has certainly been true in the past; our per-capita incomes have increased more or less in tandem with our per-capita usage of energy. Now, our population is growing, and so are individuals' aspirations.

Conservation, undoubtedly has an effect on this relationship and as the cost of energy increases, economic factors will tend to decrease energy consumed per GNP. However, unless some heretofore unknown process can be made to act to further decouple material progress from increased energy usage, California's energy demands surely will rise.

I appreciate the opportunity to take a role in reviewing for those who lead our state some of the alternative means for meeting these demands. I hope that our policy makers are already aware of the probable consequences of failing to provide the amounts and kinds of energy the people will want, including the problem of who gets how much and why. So let's look at some of the ways in which we can import the energy de-

rived from coal processed beyond our state boundaries.

II. ELECTRIC POWER

In recent years, California's consumption of electricity has grown more rapidly than its use of any other form of energy. Unless sufficient nuclear capacity is built, coal must provide at least part of the growth that we must expect if this trend continues. Thus, electrical energy is a very attractive option for importation. All such systems, however, would require long distance, high voltage transmission, with attendant line losses that are proportional to the distance. At present, these losses limit the distance for economical transmission to approximately one thousand miles. Other parameters for any electric import system include water surly, coal transport costs, ash disposal costs, and environmental impact.

Let's not kid ourselves; we can't make an omelet without breaking some eggs. Any energy system that is to make a meaningful contribution to the needs of 22 million people will have some environmental impact. I see an analogy between saying, "I hate to see any environmental impact," and saying, "I hate the thought of growing old." You've got to consider the alternative!

Conventional Power Plant

As some of the following papers will elaborate, there are several options for making electricity from coal. First, because it is current technology, I think of conventional power plants. Under present laws, such plants probably would be required to employ stack gas scrubbers, which are somewhat controversial in regard to performance and which definitely add to the cost of the power. The 3000 megawatt system that was proposed for the Kaiparowits installation was an example of this technology. Most of you here today are surely familiar with the objections raised against that project, whether or not you happen to agree with the arguments. The major point was that the level of particulates produced would reduce long-range visibility and thus diminish the scenic value of the area.

Gasification - Power

Another approach would be to convert the coal to a clean fuel gas which could then be burned in the power plant. This would certainly ease the particulate problem, but it would be more costly. This would also be considered current technology. By adding advanced power cycle concepts that are now under development, increased efficiencies could help offset these costs. There will be further discussion on this later, but it does appear that this procedure is one of the brighter stars on our energy horizon. My own

company, Fluor, is involved in test programs with Commonwealth Edison of Chicago and others, and Southern California Edison with Texaco are studying such a facility for Southern California.

In-Situ

In addition to converting coal to fuel gas with conventional gasification reactors, it is possible to gasify coal in-situ - without ever actually mining it. There is appreciable work being done now, mostly under DOE auspices, to develop this technology. The Russians have carried on such work on a semi-commercial scale for several decades, and one U.S. utility is proceeding with a program which considers the use of Soviet technology.

Just as with conventional gasifiers, such gas is readily cleaned of both sulfur and particulates. But it brings some new problems, too. Subsidence of the surface could occur, gas leakage at the surface is possible, and impact on underground water supplies is conceivable.

Fluidized Bed Combustion

Fluidized bed combustion is yet another way to use coal to make the steam needed for a power plant in a manner that promises to reduce sulfur emissions to acceptable levels under present laws.

MHD - Fuel Cells

Other modes of electrical generation, which are still in the developmental realm, are magnetohydrodynamics - MHD and fuel cell technology. Both have promise but our assessment is that these are still insufficiently developed to warrant serious consideration when we're examining options for the relatively near future. I mention it only because our DOE is providing substantial support in these areas.

III. GASIFICATION

I noted earlier that coal could be converted to a low or medium Btu fuel gas that could then be burned to produce electric power for import into our state. But a gaseous product itself could be an attractive import. There is proven technology for the conversion of coal to gas on a vast scale. Fluor is currently constructing such a plant that will process 40,000 tons of coal per day. This is for a client who has been operating a similar plant for about one-third that size for almost 25 years. It is most attractive to operate such plants near mine sites, thus avoiding the transport of useless ash or moisture.

A. SNG

California already imports appreciable natural gas, and coal can be processed to produce a substitute natural gas (SNG) that is indistinguishable from the natural

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product. There is ample capacity in existing pipelines that transport large quantities of such gas. To convert the product fuel gas from such plants as I just mentioned to SNG is a relatively simple step. Several such plants were once scheduled to be built to supply such gas for California. One of them, WESC, was a Fluor project. Various factors have combined to delay these - perhaps indefinitely. I presume that some of the reasons for the failure to move forward with these facilities is on the agenda of later speakers, but I wish to emphasize that the technology here is proven. The deterrents have politico-economic foundations.

B. Medium Btu Gas

If the gas from gasifiers is not processed to produce SNG, it will be of lower heating value. Such a gas cannot be mixed in pipelines with natural gas, but separate piping systems could be built to utilize it as an industrial or power plant fuel. The lower heating values, however, limit the distance over which the gas could be economically transported, to a few hundred miles. This may eliminate the importation to the California coast of coal energy in this form, but our border areas could conceivably be served by gasification plants located in adjacent states.

C. Synthesis of Liquids

The main constituents of such a medium-Btu gas as I've just been talking about are carbon monoxide and hydrogen. Mixtures containing these two gases are often called synthesis gas (or syngas) because a wide variety of other chemicals and hydrocarbons can be synthesized from them by using suitable catalysts and process techniques. The one such material of greatest interest on our energy scene is methanol.

Methanol, formerly known as wood alcohol, has long been a material of commerce, and its value as a clean fuel, both for transport purposes and for power generation, is well known. Almost all methanol today is made from syngas derived from natural gas or other hydrocarbons. Thus, the only different technology involved in producing methanol from coal resides in producing the syngas. Although, as I have already noted, we know how to do this on commercial scales, the economics just aren't favorable compared to starting with hydrocarbons. A recent study for an ultra-large scale plant suggests that attractive costs are attainable, but those results are still not accepted by many of us in the technical community.

As the costs of hydrocarbons rise, however, methanol from coal will become more attractive. It is easily transported, and it thus is another potential method for importing coal-derived energy.

IV. HYDROLIQUEFACTION

Liquefaction of the coal by adding hydrogen is yet another option for importing coal's energy while leaving most of its problems elsewhere. (Again, let's not try to kid anybody. That is the main thrust of such options as I've been discussing.) Our conference program shows that Session IX on Thursday is devoted to this subject. Here, I shall only point out that, by appropriate processing, coal can be reacted chemically with hydrogen to produce hydrocarbons which are quite similar to those that are derived from petroleum. The ash and sulfur from the coal are removed at the processing plants, and the liquid products can be transported as in current practice. Depending upon the perceived needs of the market place, the coal could be upgraded to boiler fuel, petroleum-like feedstock, fuel oil, or distillates, including gasoline.

The technology for hydroliquefaction of coal is still under development in the U.S.; however, semi-commercial units are under construction and commercial sized demonstration modules are being proposed for construction today. While it's true that the Germans in World War II produced liquids in this fashion, it wasn't economics that provided the impetus.

V. SYSTEMS OVERVIEW

I've mentioned several technically feasible ways by which we can import into California energy which was derived from coal. It seems to be that, in the broadest sense, we must be concerned not just with California's energy problem but with a system that includes the overall political and socio-economic welfare of a major portion of the western United States. Just because the governing leaders of our previous generations saw fit to draw certain political sub-divisions doesn't mean that people who live on one side of the boundary lines are any different from those on the other. So the "solution set" to our energy problem must include not only satisfactory economic and environmental results for Californians, but also for the residents of our neighboring states and, perhaps, of some even more distant states who might supply us with coal or water.

I described at the outset of this talk some of the evidence that our economic well-being depends upon energy. We must recognize that the penalties for failing to develop energy supplies adequately appear to be potentially harmful to our economy and our society. Our state, and indeed our country, sorely need statesmen and citizens with vision and with the courage to act to meet the needs of the future.

I would leave this audience with one closing thought. -- Technology is available; either proven or under advanced

development, to provide us with the kinds of energy from coal that we require. The deterrents to developing this source of energy are political in the case of electric power and economic and political for the other forms.

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**Session I: A SYSTEMS EXAMINATION OF THE OPPORTUNITIES OF COAL
FOR CALIFORNIA**

**Session Cochairpersons: Ronald Dickenson (SRI)
Donna Pivirotto (JPL)**

**Panel Members: Jack Moore (SCE)
Joseph H. Oxley (BNI)
William Hathaway (Fluor Corp.)**

OPEN DISCUSSION BY ATTENDEES

RONALD DICKENSON:

We have heard considerations concerning coal use in California, both electric power and non-electric applications. We have also heard considerations concerning importation of energy derived from coal outside the State. There are ten more sessions to this conference and some of them will focus more closely on some of the specific considerations brought up by the speakers in this first session. Therefore, in the vein of the overview nature of this session, we might start out with some of the general issues associated with getting coal or coal-based energy into California. For example, both Fluor and Southern California Edison have, for several years, been involved in projects for the importation of coal-based energy into the State. To kick things off, I'll exercise the prerogative of the session chairman by directing the first question to Jack Moore of Southern California Edison. By the way, we want to have a fairly quiet panel, but I see Joe Oxley is in a very difficult position. He is between an Aggie and a Razorback, so be careful, Joe.

JACK MOORE:

From my point of view, regulatory attitudes and directives are the most difficult obstacles that we have to handle. Recognizing that they are all good people was the basis of my comment to the effect that we do seem to dance to the same tune, but with entirely different rhythms. Our experience has been that as we

start to build high voltage lines, as has been done from the eastern sector of California to other states, or from the North, as we have done with high voltage DC lines and 500,000 volt lines for exchange power, we will run into adverse situations that could possibly thwart the building of out-of-state capacity. Kaiparowitz was mentioned, and this is a symphony of reasons why it is difficult to build capacity out of state. In California we have a tendency to say, "Build it out of state," while some of our people from the regulatory agency on occasion have gone over and testified against us at the out-of-state location. This is a dilemma that causes us to wonder if we are unable to adequately communicate with each other. With respect to constructing large coal-fired electric generating plants within the State, I believe this will probably be as easily done in California as in adjacent states. I think our friends in some other states that are building capacity, and hopefully they will well us some, will help our future power generation dilemma in California.

I agree that the technology is here and we will make our best efforts with these technologies to build coal-fired capacity within the State of California. Considering the stringent air pollution regulations that are continuously issued, it could be doubtful that, with present regulatory attitudes, plants would be licensed. However, as I have said before, I believe the technology is available.

During earlier comments by others, a fluidized bed combustion process was mentioned and I thought at the time that I was glad that EPRI is funding a program to study how to dump waste, which would accrue from sulfur removal, into the ocean. As you look at the solids generated in a fluidized bed boiler, there will be massive amounts of waste. If you compare this with the volume of waste or sulfur removal from other combustion processes, it is doubtful, in my mind, as to whether fluidized bed will ever be installed in California. However, I am not saying that this is not a viable solution for other parts of the country and the world.

IKE EASTVOLD:

I'm representing the desert region of the Sierra Club and I would like to address my question to Mr. Moore. You mentioned your eastern desert proposal, your 1500 megawatt coal fire proposal. Are you only looking at the eastern desert, or are you looking at alternative locations outside of the eastern deserts of Riverside and San Bernardino Counties?

JACK MOORE:

If we are going to talk about coal in California, then we must look generally in the eastern desert area. We are looking specifically at the ill-fated Vidal Nuclear Station site that is located just to the west of the Colorado River. We are also looking at sites in the Barstow area. The coal-fired plant announcement is new enough that only preliminary studies are under way and there will be 10 or 12 sites reviewed before we are through. We must take into consideration many elements before a decision can be made on a plant site location. There are hundreds of parameters that must be reviewed; such as one that concerns the Vidal site, which creates a problem because this is the mating area for the desert tortoise. The impact of the plant on that animal will be a large part of the ecological review.

IKE EASTVOLD:

I think there are some Indian reservations where a certain amount of such mating goes on very close to that site also. I would like to know if you anticipate suggesting alternative sites to the Vidal which involve a different transmission system and different water supply scenario.

JACK MOORE:

Certainly, we look at every possible water supply because a coal generating station of that size will take 30,000 acre-feet a year of water. That is a little high, but in that order. Fresh water, brackish water, whatever is available, we'll use it. Also, we could get into the question as to why we locate in the desert when we have

a great big ocean, but "gee" there is Pandora's box for you!

RICHARD DIEHL:

Aerojet Energy Conversion Company, directed to Mr. Moore. Three very short questions: (1) What do you look to be the percent growth demand for electricity? (2) Based on that answer, what is the reserve capacity that you are looking for? and (3) Cou'd you elaborate a little more on the lead time for a coal-fired plant to go in California, realizing for example, that in the U.S. for a nuclear plant, we are talking about 12 years lead time.

JACK MOORE:

I guess I could be a little facetious and talk about the lead time on Kaiparowitz, but that would not get us very far. If you go through the Notice of Intent process that we have for siting in the State of California, you could expect that, at best, you would have a permit to build within, say, three years. For a nuclear plant, certainly the PSAR, or the Preliminary Safety Analysis Report, is a document that is taller than I am. For a coal plant, by investigating the breakthroughs that the Japanese are supposed to have made in the fluidized bed, ammonia injection, and such things as this, you could wind up with a document equally as thick. The time spent, in the realistic world to cover any eventuality, could equal the same length of time for coal as for nuclear. In my talk, I said that with everything on our side, we could have a coal plant in operation in the latter part of the 1980's. When we say operation, we mean that it has a capability to carry load, that it is not a facility sitting there that we are trying to get to run. It means commercial operation.

I think the chart showed about a 3 percent demand growth rate and that could change considerably. If you look at the situation of the more stringent air pollution regulations, not only from the federal government but in particular the ARB in California, you can see that many people who are burning oil today may consider purchase of electricity from us to fill their energy needs. However, our company does not feel that it is economical to build new

capacity. When we talk about 5 hundred megawatts a year capacity growth, this would require large capital outlay which would be hard to recover. Therefore, we are spending money to sponsor "conservation" in order to avoid building new capacity and to save fuel. If our customers ask for new capacity, we certainly have to fill the need.

The second part of the question was how much reserve capacity do we feel we need. We have reserve capacity today, depending on what the outage situation is, as high as 20 percent. We think that a reasonable reserve margin can be as low as 15 percent. But let me caution that this is not a magic number, it depends on the condition of a system and the diversity of energy generation plant that is available. As was mentioned this morning, the reason we have coal capacity on our system is that years ago we felt that we needed that kind of diversity. Also, this is why we pushed for nuclear. My chart showed that we believe that nuclear is the option that must be pursued. That doesn't mean that we should not exercise our best effort in the development of coal-fueled electric power. Certainly, we don't want to have a process using coal that would cause some of us to have to explain to generations of the future that the reason why we wasted large amounts of our coal was due to the need to first make gas or a liquid at an efficiency of say 60 percent, and from the fuel processing plant then burn the gas or liquid in another type of plant in order to get electrical energy.

NEAL COCHRAN:

I'm with the Department of Energy. My question is directed to Mr. Hathaway. Prior to the question, however, I have one brief comment with respect to something he said. He suggested that everyone did not necessarily agree with a recent Department of Energy study on a cost of methanol and I suggest to him that doesn't necessarily mean that it is wrong, any more than is their study, which they did for us on converting coal to gasoline. Everybody didn't agree with it either, but that remains moot as to who is correct. My question is concerned with the use of gasifiers similar

to the ones recently evaluated by your company for EPRI as a means of generating electricity. I would appreciate a comment as to what the effect of the more efficient of those might be on the cost of syngas and the ultimate use of that gas, either for electricity or conversion of liquid; what effect might that have on the economics of those processes?

WILLIAM HATHAWAY:

Regarding the first comment concerning the cost of methanol. The statement was made that most of these things really still are on paper and until we really get some commercial practice in the real cost and go through the pains of permit obtaining, or whatever it takes to get something built, we do dwell in estimates. Estimates have certain degrees of accuracy. Different people have different opinions, you just heard two of them. Concerning the effect of gasifiers, and I guess improvements in gasifier technology, when you get to the overall cost of facilities, this gets diluted to some degree, improvements and cost, we're again dealing with estimates and the effect would be an improvement but it wouldn't be very great. I know that is not an answer, but since I really don't have the exact information at hand, I just know that it is not a large effect on the cost of the syngas.

DONNA PIVIROTTO:

I just want to ask a quick question. Could you, Mr. Hathaway, rank in some sort, which ones are the nearest term of options you talked about. You talked about a lot of options, but you didn't really say which ones are near term and which ones are farther out. What are your favorite three?

WILLIAM HATHAWAY:

I don't know whether I can list my favorite three or not, but certainly let me say this, of the ones that we're building or getting ready to build, which certainly all rate as proven technology, all do employ the Lurgi gasifier. This is a well-

known gasifier, it's proven. Certainly the Texaco type gasifier has been utilized for heavy oil and it is well under development and it won't be very long before that will be available.

I think gasification is really being practiced today. Now liquefaction is going the syngas route, but in a different fashion. Hydroliquefaction is under development; however, it is just a few years down the road.

LARRY MARGLER:

I am representing the Environmental Science and Engineering program at UCLA. Mr. Oxley, you mentioned a little bit about coal fired furnaces in individual homes. I was wondering if you could say a little bit more about how widely used they are presently and also how much more that use could be expanded in the face of environmental constraints.

JOSEPH OXLEY:

They are not very widely used in Columbus, Ohio, at all. That was the only home that I knew in our neighborhood that had a coal-fired stoker. In some areas, they have been outlawed. I think that is true in Pittsburgh, which is the center of the coal country. So their use is relatively rare and the question is if they could be used more in the future and particularly in California. I think the answer is yes. They could and will be used more. How much more I really don't know. We do need to develop a way to control emissions better from the chimney. As I said, that was not necessarily a typical emission level that we saw in the slide, particularly if you realize that when you start a fire you frequently start out with a lot of smoke. On the other hand, there is a huge market opportunity for putting something on the chimney to take out emissions, especially during start-up. So I think coal will be used more in individual homes. However, I really don't think the use in individual homes is going to have a major energy impact on California, at least not for several decades. In terms of residential complexes, however, the impact could be considerably greater.

ART FRIEBER:

I am representing the Western Division Naval Facilities Engineering Command. I would like to ask a question about the increased requirements of personnel. In the government, of course, we could use cheaper fuels, we could increase our productive capacity to lower our costs, but we have a problem; increased costs of personnel. It's obvious that personnel costs would be much greater because of the personnel requirements for handling coal in storing, transportation and burning. I wonder if Mr. Moore would comment on that in his new contemplated installations?

JACK MOORE:

Certainly the transportation of coal costs and handling at the plant are higher. The photograph or the artist rendering that I showed for the purpose of giving you a visual feel for the additional equipment, such as silos, belts, and coal grinders and is only front end equipment. I would say that with regard to the transportation of coal, we have found that our Mohave Station experience that a slurry pipeline has been successful. It has transported coal at rates that I'm certain are below those that you could achieve by rail. Primarily, the rate structure itself, plus handling at the site, because the so-called 50/50 slurry coal and water arrives at the plant, goes in the tank just as oil would, it is then ground for the purpose of removing water and I won't get into all the other complexities; but certainly, it is more expensive to handle and burn coal. We are talking about today's market of \$1 per million BTU and future contracts that might be \$2 per million BTU for coal, and comparing that with gas at \$5 per million BTU, or methanol at \$8. A comparison of these figures shows that you have a lot of money left to handle coal on site.

ERIC JOHNSON:

I work with the Black Businessmen's Association of Los Angeles. Mr. Moore, could you address the whole issue of the dilemma of coal use in the State further? The other thing is I am a bit foggy about all the technical jargon, but could you translate the impact

for the intercity resident by the coal use within California?
Also, do you have any ideas as to business developments or
opportunities in the coal field?

JACK MOORE:

I think the greatest impact on use of coal in California or the cities would be the fact that coal energy in the form of electricity would be transported to the city so that the direct impact of any air pollution would not be in the city. However, I wasn't being facetious when I mentioned the desert tortoise as something that would keep a company from developing coal out of the urban areas. Now, also for the intercity, thus for the lower income people, there is no doubt in my mind that in the immediate future coal will be the way to go just due to expected increases in the price of oil that I mentioned earlier. Coal will keep energy costs down, and I ended my talk by stating that our goal is to develop coal to keep the cost of electric energy down. This will be in spite of all the apparatus that will be on the back end or front end of a coal plant for air quality reasons. I believe anything that might develop for generating plants within the basin here will be very expensive and for this reason the cost will be lower for remotely located coal. However, we should keep in mind that nuclear will also be needed if we are going to keep the cost of power down.

SESSION II

FUTURE ENERGY DEMANDS IN CALIFORNIA

N79-27601^{Dy}

ELECTRIC ENERGY DEMAND AND SUPPLY PROSPECTS FOR CALIFORNIA

H. G. Mike Jones
Manager, Electricity Planning Program

California Energy Commission
Sacramento, California

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I. RECENT HISTORY OF ELECTRICITY FORECASTING IN CALIFORNIA

The debate over forecasts of electricity demand in California has been going on before the California Energy Commission for over two years, and before the Public Utilities Commission and State Legislature for over five years. This debate on electrical demand forecasts was engendered by the strong environmental protection sentiments of the late 1960's, most notably spurred on by the Santa Barbara Channel oil spill. There was further a belief in some quarters that California utilities were overexpanding and might fill the coastline with nuclear power plants. The adoption of the Federal Clean Air Act Amendments, the National Environmental Policy Act (NEPA), and the California Environmental Quality Act, all in 1969, and the establishment of the California Coastal Zone Commission in 1972, signalled a major environmental movement to regulate utility growth.

The debate over the rate of growth in electricity demand in California, where some noted that high projections are potentially self-fulfilling, led to the establishment of the California Energy Commission in 1975. The debate over electrical forecasts has not been eliminated. However, the California Energy Commission prepared statewide electricity demand forecasts with assistance and critical review from the State's five major utilities: Pacific Gas and Electric, Southern California Edison, Los Angeles Department of Water and Power, San Diego Gas and Electric, and Sacramento Municipal Utility District. The Commission officially adopted a "most likely" forecast for use in approving new generation facilities. While the forecast remains controversial, it is the first fully documented electricity demand forecast officially adopted as a basis for approving on a statewide basis proposals to construct new generation stations.

Since the methods and significance of forecasting are poorly understood by the layperson, there is more often than not a somewhat confused intuitive reaction to forecasts and the question of forecasting. Before describing the historic and current electricity demand and supply situation in California, I would like to make a few brief observations on this complex subject.

Why should we concern ourselves with forecasting? Besides, as most observers must be aware, aren't forecasts almost inevitably wrong? It is commonly believed and claimed that our rate of economic growth and the current level of economic activity are intimately tied to the use of energy. Thus, forecasting well and providing adequate energy supply is essential to our economy. Although there is almost no disagreement on the

basic importance, there is substantial controversy about what the exact relationship has been or needs to be in the future.

Trends in foreign countries' energy use per capita and energy/GNP ratios are often used to attempt to generalize that less energy intensive patterns are compatible with rising standards of living and are feasible for the United States. However, these comparative assessments are often flawed by a failure to properly recognize basic economic, geographical and natural resource differences, such as the large, inexpensive hydro resources in Norway and Sweden, which allowed energy intensive industries to be developed. We can also observe that proportionally less energy is utilized where energy prices are high relative to the costs of other inputs such as capital and labor. For example, a recent study of European electricity pricing and load management experience by the Rand Corporation* showed that the European utilities selling electricity at rates reflecting daily and seasonal supply cost differentials affected significant changes in both the intensity and time of electricity use.

Accurate forecasting is important because it determines the magnitude and lead time of major energy investments. The high cost of new baseload generation stations (a 1,000 Mw nuclear station now costs up to \$1.5 billion; a coal station, \$1.3 billion) and the extended time horizon over which these expenditures are made (now well over 10 years), means that economically optimum investment decisions can only be made if we have accurate forecasts.

Accurate forecasts are also important to assess the financial feasibility of utility supply plans. In the Energy Commission's recent examination of the feasibility of financing the proposed Sundersert Nuclear plant of San Diego Gas and Electric, it was determined that financing the expansion proposed by SDG&E would cause a severe strain for that utility unless substantially higher rates were approved by the California Public Utilities Commission. The demand forecast is a major factor in determining rate of return.

What is our historic experience with electricity demand growth in California? Historically, electricity demand has grown at rates above 7 percent, with sales doubling in less than ten years. Major factors influencing this growth have been the cheapness and convenience of electricity. The real cost of electricity relative to other goods and services has declined steadily since the 1920's. Also contributing have been promotional

* "Electricity Pricing and Load Management: Foreign Experience and California Opportunities," B. Mitchell, Rand Corporation, March 1977.

pricing and declining block rates for industrial power. These latter two factors have been major targets for critics of the utility industry, especially where the rates have not reflected marginal costs of service. Believers in the logic that utility forecasts are self-fulfilling prophecies have noted that declining block rates which do not reflect the true marginal cost of supplying power provide an uneconomic stimulant to demand growth.

The sharp jump in the price of oil in 1973-1974 has resulted in higher electricity prices, reduced electricity demand growth rates, and increased public awareness of the need to conserve. The economic recession which followed also contributed to the sharp drop in the rate of demand growth in California.

The declining rates of growth in demand contributed to the view that tighter regulation of utilities was necessary to prevent overbuilding. In addition, the scarcity of good sites and water at inland sites, and air pollution in urban centers were cited by proponents of tighter regulation. On the other side, many utility analysts claim today that the utilities are tending to under capitalize, and under build, reflecting the high cost and difficulty of raising capital in the face of stringent CPUC rate policies.

The current excess capacity situation for the Los Angeles Department of Water and Power and the deficit in required reserves for Pacific Gas and Electric,* as demonstrated by the reserve margins in Figure 1, support our belief that there are grounds for improving our forecasting and planning applications.

The important task at hand is to learn from the past and establish public goals which provide for future economic growth. This is the responsibility facing the California Energy Commission, Public Utilities Commission, Air Resources Board, and other State regulatory agencies concerned with energy matters.

What has been our experience with post-embargo electric growth? As noted above, our historic electricity growth rate of more than 7 percent has dropped substantially in the last few years. Two years ago, in their official ten-year forecasts, the five major California utilities forecasted a growth rate of approximately 5.1 percent for energy sales, and 4.8 percent for peak demand (1976-1985). Figure 2 shows the peak demand forecast and the adopted Energy Commission forecast which provides the basis for Commission approval of new facilities. The Commission's lower growth rate forecasts were approximately 4.5 percent for energy and 4.3 percent for peak demand. Actual experience to date has shown that sales grew at approximately 2.5 percent in 1977, and peak demand by only 0.5 percent. A one percent difference in the forecasted rate of growth translates into roughly a 3,500 Mw capacity difference statewide by 1985.

* The delay in the licensing of PG&E's Diablo Canyon's 2200 Mw nuclear station, and hydroelectric capacity lost in the 1976-77 drought, contributed to their low reserve margin.

Based on the utilities' March 1978 forecast submittals, shown in the table below Figure 2, one can see a general lowering of the utilities' previous peak demand forecasts from 4.8 percent to 4.1 percent per year between 1976 and 1985. It should be noted that a related change has been a much more explicit measuring of the effects of conservation measures, such as mandatory State building and appliance standards and utility conservation programs.

How do the forecasts displayed translate into capacity needs? Forecasts of peak demand dictate required new capacity to provide reliable peak demand service, as well as to meet baseload energy needs. It is also important to recognize that capacity is added to a utility system for reasons in addition to simply accommodating demand growth. Economic considerations, for example, may cause the addition of new plants and decreased use or placement on standby of old plants. Further, reliability considerations and rising fuel costs may lead to the addition of plants with different fuel requirements.

How is electricity generated in California today? The fuels picture in California has changed dramatically over time, as shown in Figure 3. Cheap and abundant natural gas has been the dominant electrical energy source, with hydroelectric energy placing second. Beginning in 1970, natural gas availability dropped drastically, replaced by increased fuel oil use. In the 1976 and 1977 drought years, California's hydroelectric output was more than halved. In 1976 this loss was offset by increased imports of Northwest hydroelectricity; this supply was also lost in 1977, as the drought hit the Northwest. Our thermal generation in 1977 was supplied 55 percent from oil, 28 percent from natural gas, 12 percent from out-of-state coal, and 10% from nuclear and geothermal sources.

In their 1976 planning submittals to the Energy Commission, the five major utilities proposed a large increase in nuclear generation, expecting that fuel type to account for 36 percent of expansion from 1976 to 1985; oil to account for 24 percent; coal 18 percent; and geothermal approximately 8 percent. In the following 10 years, 1986 to 1995, nuclear generation plants were anticipated to account for 75 percent of all additions.

In their most recent planning submittals (March 1978), the utilities reflect the uncertainties facing them in the choice of baseload generation technology. They have cut plans for new nuclear generation and PG&E now does not specify type of plant after 1987. This is essentially the driving force behind the coal conference today.

Coal use for California electricity generation is now limited to out-of-state facilities. California utilities currently own jointly with other utilities three out-of-state coal facilities; namely, Mojave, Navajo, and Four Corners. The Los Angeles Department of Water and Power owns 790 Mw and Southern California Edison owns 1650 Mw of this out-of-state coal capacity. (Additional energy is derived from out-of-state coal by contract.) Planned out-of-state coal expansion is

very important for Southern California at this time - the Utah Intermountain Power Project is considered an important resource in meeting future electrical needs along with the Nevada Warner Valley Project.

To date we have only one firm plan for in-state coal generation: PG&E's proposed Fossil 1 and 2 facility, which would provide 1600 Mw of capacity beginning in 1985. The Energy Commission is currently reviewing PG&E's proposal, and will also be reviewing a small coal gasification project proposed by SCE.

Other coal facilities specifically identified as potential resources by the State utilities, but with widely varying levels of uncertainty at this time, are as follows:

- SCE: East Desert Coal - 5000 Mw
- SDG&E: Coal 1 and 2 - 2000 Mw
- State Department of Water and Power: Three 330 Mw Coal units

II. DEALING WITH FORECAST AND REGULATORY UNCERTAINTY

The often quoted prescription to cure capacity planning uncertainty often referred to as the "utility view," has been to argue for:

- Reduced regulatory review time
- Accelerated siting of conventional non-oil power plants
- Increased forecasts or reserve margins to compensate for uncertainty

While these arguments have a place, they fail to adequately reflect the value and potential of:

- Conservation as an option to new capacity expansion
- The benefits from better interstate and statewide system integration

And most important to this conference, these arguments do not address the need for a fuels policy introduction of new fuels and technology, most notably for the demonstration and use of conventional coal with advanced cleanup and advanced coal combustion or clean fuels from coal for California.

In summary, several of the points made above need to be reinforced; specifically, these are:

1. It is not apparent that electrical energy demand growth will be substantially lower than we or the utilities thought only two to five years ago. General acceptance of this fact is essential to establish a sound basis for supply policy discussion.

2. Coal combustion utilizing our abundant supplies in western states and Alaska is necessary in and for California, but there are insufficient utility proposals at hand for conventional or advanced coal systems.

3. Conservation effects, although difficult to predict, have a substantial potential to further reduce energy needs, and should be a part of all resource development strategies.

4. Government regulatory agencies share an obligation for meeting energy demands and need to provide adequate policy direction. At the same time, the utility industry must recognize the reality of current economics and constraints to conventional fuel options, both oil and nuclear, and assist the State in developing a realistic program to use coal cleanly in California.

LOS ANGELES DEPARTMENT OF WATER AND POWER
AND PACIFIC GAS & ELECTRIC
PRESENT AND PROJECTED RESERVE MARGINS

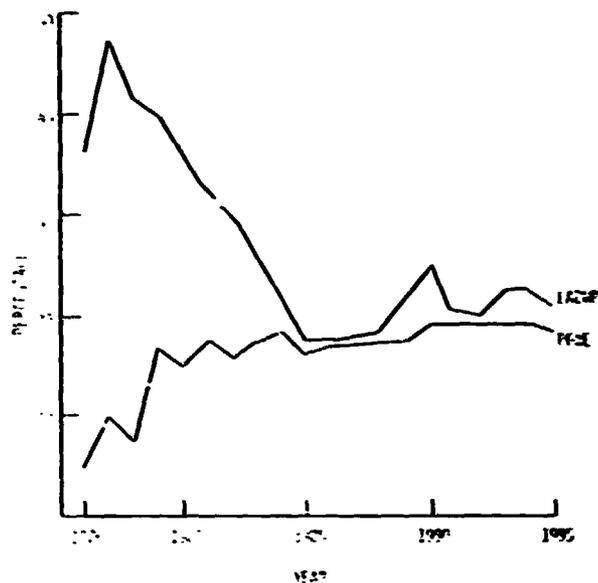


Figure 1

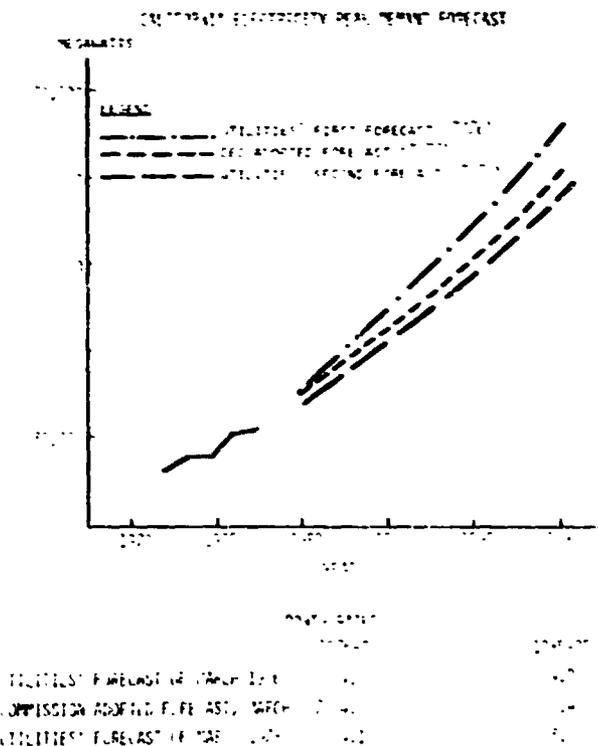
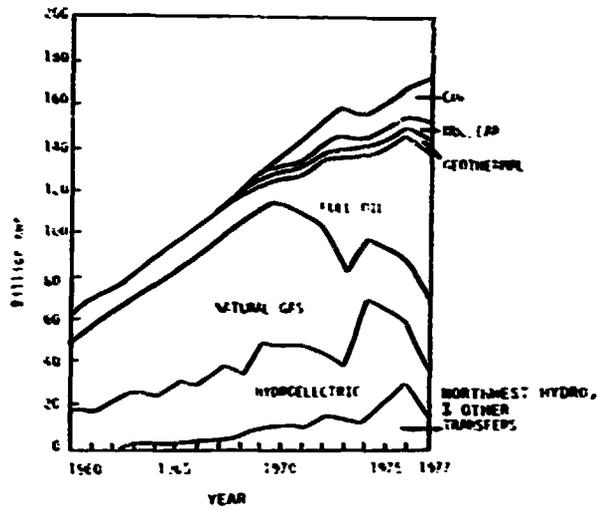


Figure 2

**CALIFORNIA ELECTRICITY PRODUCTION
BY SOURCE**



SOURCE: CALIFORNIA ENERGY COMMISSION'S 1977 BIENNIAL REPORT, VOL. I, FIGURE 6, P. 7.

Figure 3

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COAL'S ROLE IN CALIFORNIA'S ENERGY NEEDS

Nolan H. Daines

Pacific Gas and Electric Company
San Francisco, California

ABSTRACT

California's post-industrial society demands confidence in the energy supply system as an essential ingredient for social harmony and adequate job creating capital investment. Confidence requires policies which balance supply and demand using believable methods with adequate allowance for the unexpected, reliance on diverse sources and locations, respect for our environment, sustain our individual freedoms and provide opportunities for economic mobility. Coal will play only a part, but an important part, in a multi-faceted energy policy using numerous energy sources and systems, conservation techniques, and cooperating societal institutions. Today's extensive and challenging research and development provides the foundation for future technologies which will further remove the environmental effects associated with coal.

TEXT

Thank you Mr. Chairman, good afternoon ladies, gentlemen and fellow session panelists.

When I first started formulating this talk, being an engineer by training, I was tempted to use a number of precise, multicolored charts. These would have shown you one utility's view of coal's future role. We have that kind of information and it is useful in its proper place. However, the issues surrounding coal's use in California transcend the normal utility practice of gathering demand information and formulating a resource plan to meet it. The issues are public issues and will not be decided by utilities alone. Right now the public's estimate of coal's role is ambiguous. Coal's place will gradually evolve over time and will be the product of innumerable decisions. I hope its role will not be the result of too much indecision and neglect. The decisions will depend on factors ranging from OPEC nations to the outcome of research now planned or underway, and from the ballot box to the ultimate energy user at home and at work. We will be influenced by honest, sincere people with diverse views and people with hidden objectives in mind will attempt to mislead us.

This conference will perform a vital service if it helps communicate to Californians the problems of meeting their energy needs and the true nature of coal use. For many Californians today have misconceptions about both of these. And coal will be measured less by what it actually is, than by the perception of what it seems to be. I am hopeful our perceptions will be helpful in forming yours.

FIRST IMPRESSIONS COUNT

First impressions have a great deal of influence and, for many, the mention of coal brings visions of smokestacks billowing huge clouds of

black soot-filled smoke and mountains of ash. Historically, that was frequently the case. But technology has made great strides both in reducing the amount of coal needed and cleaning up that which is required. The Centralia, Washington coal plant of Pacific Power and Light Company shows what has been accomplished. It has two units of 665 megawatts each. This plant is the source of some of California's present electricity supply imported from out-of-state coal generation. They are sending 30 percent of the power from that plant to northern California and will continue to do so until 1982 when it will be needed in the Pacific Northwest. There are two stacks and occasionally one is shut down for maintenance. But, if asked to point to the stack which is operating, visitors are hard pressed to correctly identify it. There are no visible emissions (Ref. 1). Centralia shows how coal use has changed for the better. Moreover, technology has further improved since this plant was completed in 1972. Our proposed coal plant in northern California will have even less soot and sulphur emissions than Centralia's. For that matter it will be less than our existing oil plants.

COAL MAY EVENTUALLY GIVE US NATURAL GAS TOO

My discussion concentrates on coal's potential electric supply role. Coal is also viewed as one of the major potential sources for substitute natural gas, often called SNG. LNG, or liquefied natural gas, is a major potential source now available to us. Making SNG from coal has not yet been demonstrated on a commercial scale. At PGandE, we are continuously working towards reaching that goal by reviewing promising technologies and ways to affirm their commercial feasibility. We expect that coal will play a future role in supplying pipeline gas to California.

NEED FOR ELECTRICITY FROM COAL

We at PGandE believe there is a need for large, economic, base load electric generation in California. We also believe coal is the best alternative available to fill some of that need and may be the only alternative at the time it will be required. Our announced plans to build two 800 megawatt coal units in the mid-1980's result from this belief. When completed, each unit will supply the electric needs of about half a million people. By then northern California's population will have grown from its present nine and a half million to nearly eleven million.

The key factors driving our need for new energy sources are not only the increasing demand, but California's almost total dependence on oil and natural gas. Nearly 85% of all California's energy comes from these two sources (Ref. 2). Reducing this dependence means we must develop other energy supplies faster than demand increases. That's one of the reasons why conservation is vital. The slower electric demand grows, the faster we can reduce our dependence on oil and gas.

Conservation is essential and all acceptable techniques must be used. Conservation is not new to PGandE. One of our conservation programs goes back to 1914 (pump testing). Since the oil embargo, we are planning a larger role for conservation, and ten years from now, it will be saving more energy than our two coal units will generate (Ref. 3). But, even though conservation is saving a great deal and even though two-thirds of our new plants won't use oil, by 1987 we'll need more oil and gas than today; and, that assumes the planned coal plant is operating. Looking at it from a different perspective, if three times the forecasted conservation occurs and our coal plant is built, oil and gas in 1987 will still be needed to generate twice the amount of electricity generated from coal.

Economics favor coal over oil. Not only will a new coal plant produce less soot and sulfur air emissions than our existing oil plants, but it will cost less too! Power from a new coal plant costs less than just the oil needed to run our existing plants (Ref. 4).

Before leaving the discussion of electricity demand forecasts and conservation it's important to help clear up one point. There has been a lot said about the subject as it relates to the need for new power plants and it is confusing. Demand forecasts are not that different. The Energy Commission's forecast of electric needs in our service area is essentially the same as ours. Both forecasts are about 4 percent annually, with the Energy Commission's eleven-year forecast at the same level as our ten-year forecast. Both will probably be proven wrong. In fact, the Energy Commission has indicated that its 1985 forecast for all of California may be 8,900 megawatts too high or it may be 8,300 megawatts too low (Ref. 5). This difference of 17,000 megawatts is more than PGandE's total existing generation. It is more than ten times the size of our proposed coal plant. This measure of uncertainty poses difficult questions when assessing the State's need for coal. But the issue must be confronted.

From this uncertain perspective, it is our view that there exists a large need for secure, reliable energy sources. These are needed not only to meet our customers' increased energy requirements, but also to decrease their dependence on oil. Electricity from geothermal, hydroelectric, solid waste biomass, and co-generation are all helping to supply our power today and we plan to utilize these and other alternative resources to their full feasibility in the future. But alone they will not be enough to stem the tide of oil. We expect that solar energy will continue replacing some natural gas in water and space heating, but will not be a significant energy producer in the 1980's. After implementing acceptable conservation, coal and nuclear are the only realistic base load alternatives available today to significantly reduce our dependence on oil for electrical generation. They are credible because they have a long-term assured domestic fuel supply, they represent a mature, commercially proven technology, their generation is economical and the large transportation system needed for coal exists.

COAL USE TECHNOLOGY

I mentioned earlier that great strides had

been made in cleaning up coal but it's not all roses.

Using the best combustion controls available, nitrogen oxides will likely be higher from coal than oil. That's important because they may be a necessary ingredient for smog. Cleaning devices may become available, and we hope they do. On this point, I believe we should clear up some confusion. Leaders in California's Executive Branch have been searching for an alternative to Sundersert. Your Legislature directed that it be "economically comparable", "technically available" and "environmentally acceptable" (Ref. 6). In the process, they were told that nitrogen oxide cleaning technology using ammonia and removing up to 90 percent is demonstrated, technologically proven and can be purchased from a number of manufacturers (Ref. 7). One might get the impression from this that the only issue remaining in cleaning up nitrogen oxides was who is going to get the equipment order and how much will it cost? Unfortunately this is not the case, especially for coal. All the coal pilot tests for this high level NO_x control are less than one megawatt, so considerable scale up will be required. It is unknown how much ammonia will escape to the atmosphere or its effect on the environment when it does. Large scale tests of nitrogen oxide control have been on oil plants burning very low sulfur fuels. But there are indications that the higher sulfur contents of coal may have side effects which would shorten the life of boiler and reduce its efficiency. And, the combustion gas after sulfur removal may be too cold for the necessary chemical reaction removing nitrogen oxides. Particulates may cause similar problems. At PGandE we are hopeful that these problems can eventually be overcome, but we don't believe it would be responsible for us to tell you they don't exist.

Air emissions are of vital concern to California. This concern is not without justification and we believe it is possible to build coal plants today which will meet the expectations and requirements of Californians. The future may bring better control technology but, even with the best conceivable emission controls, California's air will be cleaner with a generation mix that includes some nuclear power plants.

Burning coal produces prodigious amounts of ash and scrubber wastes. We believe that the technology is available such that by mixing these two we can produce an inert earthlike substance which can be landfilled without harm to the environment.

In the years ahead the options we have to choose from will be more plentiful as today's research is successfully completed. And PGandE spent \$50 million last year in research and development to help assure that we have more options available. As part of the nation's broad energy research program, the extensive efforts on coal should have large payoffs--not only in lower cost, more efficient and cleaner coal conversion options, but also by giving us a better understanding about what aspects of coal use are most undesirable. With that knowledge we can concentrate our efforts on their mitigation. We are optimistic that some new technologies will survive the challenge of technological feasibility, cost competitiveness, environmental sensitivity and public acceptance.

Besides better ways to use coal, the nation's efforts will likely bring forth economic and acceptable techniques to capture electric power from wind and the sun's rays and other renewable sources. As that occurs we stand ready and able to implement them. But, today we don't know which will pass the test nor when. The future will always hold the prospect of improved technologies waiting just over the horizon and we must strive for them. But, we also must assure that the economic engine providing the means to reach these greener pastures has enough fuel to get us there. So, we must build base load generation using today's proven technology.

ENERGY SUPPLY MUST BE CERTAIN

At the start of this talk I stated that people make decisions based on their perceptions. An important test for the State's energy supply policies will be how credible they are perceived to be by business decision makers. Recently Fortune magazine told us that many companies were avoiding expansion in or moves to California, and making job-creating investments elsewhere (Ref. 8). Among other reasons, uncertainty concerning energy was cited as a principal cause. As the article relates, one manufacturer states that California doesn't understand how uncertainty about energy translates into increased risk and increased risk dampens enthusiasm for investment. We can help eliminate this perception of uncertainty by adopting an understandable State energy policy that draws support and confidence from a broad spectrum of interests. For the need is not for coal per se, but for reliable energy equal to our requirements.

PG&E's future is with California serving the needs of its citizens. We want to work together with other groups on the immense problem in reducing our dependence on oil and natural gas while fueling a growing economy. We believe the job should be started today with the best that's available. For energy production cannot be turned on and off at will like a faucet, nor can it be called into existence at a moment's notice. With lead times of eight or more years for a coal plant, the principal regulatory agencies must recognize that we are beginning to run out of time, and speed up their procedures accordingly. The Governor, the legislature, and the public at large should also understand the need for, and insist upon, the expedited authorizations required to bring these essential new energy supplies in on time.

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ENERGY SUPPLY AND DEMAND IN CALIFORNIA

Edward D. Griffith

Atlanti: Richfield Co.

INTRODUCTION

It is a great pleasure to be here and to take part in this program on Coal Use in California. The program chairman asked that I talk about the petroleum industry's view of future energy supply and demand in California, but I must say there is not an industry view as such, at least not one that I am aware of. All I can do is represent a view of my own, which reflects some of the thinking of my colleagues at Atlantic Richfield Company, but for which I take full responsibility. It does not necessarily reflect the views of the Company or others in the industry. The issues I plan to discuss relate to California, but I am going to present some data that relates to Petroleum Administration for Defense District V, (PADD V), which is the West Coast of the United States - California, Alaska, Arizona, Hawaii, Nevada, Oregon, and Washington. California, of course, is the predominant energy user in this group.

What I plan to talk about are my views on future energy demand on the West Coast of the United States, how that energy demand translates into demand for major fuels, and identify the major uncertainties in determining what future demand may be. I will then discuss the major supply options that are available to meet projected demands and the policy implications that flow from these options.

There were some key assumptions that must be made in developing any projections about energy supply and demand. I would also like to point out that the data I will present is not a forecast, it is only a scenario - one view of what the energy economy might be, given the assumptions that I made. I certainly don't represent that this is the only possible view. The real world will probably be different, but I did make some assumptions that I believe are plausible about key determinants of energy supply and demand.

First, real GNP growth in the United States is assumed at 3.4 percent per annum over the next 15 years. This is a particularly important assumption as the prime determinant of energy demand is economic activity. The more people drive, the more steel you make, etc., the more energy you will need. Historically, the energy demand growth rate has been about equal to the GNP growth rate. In the future we expect the growth rate in energy demand to be somewhat less than the growth rate in real GNP, reflecting real progress in energy conservation. In this case I

have assumed a 2.4-percent average annual growth rate for total U.S. energy consumption compared to a real economic growth of 3.4 percent.

I also made an assumption that real world oil prices would be level or "indexed," that is the OPEC price of oil would be constant when adjusted for inflation. U.S. oil prices are assumed to rise gradually to the equivalent of world price by the middle of the next decade, and U.S. natural gas prices similarly rise to the energy equivalent of oil, but continue to be controlled. I also assumed that coal use would be encouraged as a matter of Federal policy. Nuclear energy would continue to grow, although that growth would be somewhat constrained by policy and various delays in the licensing process.

ENERGY DEMAND

Table I shows projected energy demand by major market sectors, based on the above mentioned assumptions, for PADD V. What we see is an expectation that energy demand in the major market sectors will continue to grow, but it will grow more slowly than historic levels. The household/commercial sector will grow at a level that is consistent with expected population growth and household formation, and the industrial sector will grow just slightly less. The transportation sector will have a relatively low rate of growth. Gasoline demand is expected to flatten out as cars become more fuel efficient in keeping with Federal mileage standards, but that will be partly offset by an increase in miles driven and increased demand for diesel fuel and jet fuel.

The net result is final market demand growing about 2.2 percent per year over this period of time and total primary energy demand growth of 2.8 percent per annum, which can be contrasted to historic levels at around 4 percent a year before 1973. This marked improvement in energy consumption growth rates is a result of the assumptions about lower economic growth and expected progress on energy conservation. We have seen quite a bit of conservation already and we expect energy to be used even more efficiently in the future.

The electricity conversion losses shown separately represent the difference between the amount of energy that goes into producing electricity and the useable electric output. It is proportional to the growth in electricity demand

which is expected to be higher than the growth in total energy demand, or about 4.5 percent a year. It is slightly higher than the most recent projects of the California Energy Commission. Expectations of electricity demand growth have been falling consistently for several years and are now far below historic growth rates. This is an area of major uncertainty in the overall energy outlook and has important implications on policy choices relating to both coal and nuclear energy. What does seem clear is that electricity will continue to play an expanding role in our energy economy.

Having developed projections of energy demand by market, we must then ask which fuels we expect to provide this energy. Table II indicates the mix of primary fuels that I believe are consistent with the assumptions made and the projected market sector demands. Oil consumption grows at much lower than historic rates with the largest increase in the 1976-1980 period, reflecting an expectation that industrial users and utilities will be shifting away from natural gas toward oil. At the same time, total natural gas consumption grows slowly as industrial and utility demand declines, but the household/commercial sector grows modestly.

Coal and nuclear energy now make a small contribution to total West Coast energy supply, but are starting to grow rapidly. This rapid growth rate is expected to continue from their very low base. Even by 1990, however, the total coal and nuclear contribution will be only slightly larger than gas, and only about half that of oil. The projected coal consumption is primarily for electricity generation. It reflects specific plants under construction or planned that are all outside of California, with the largest number in Arizona. Nuclear energy has a spectacular growth rate due to the small base. However, these projections were prepared before the recent decisions on the Sandesert nuclear plant, so that the 1990 number does include a contribution from that plant that will not be realized. Some would argue that the exclusion of Sandesert will be offset by lower electricity demand, while others have proposed coal fired plants in California, the topic of this Conference. Hydropower is expected to return to normal levels with small capacity increases. Other sources (solar, geothermal, wind, etc.) show a fairly large growth rate starting from a very small base. While growing rapidly, the contribution to total energy of these other sources will be still quite small in 1990.

It is important to note the mix of energy in 1990. You see that oil and gas are still our major sources of primary energy, even though others are growing more rapidly. If we truly want to understand the outlook for coal, we need to assess it in relation to nuclear and other new energy forms, but we must also look at how the traditional fuels - oil, gas, and coal - relate to one another in the fuels market. As one of our purposes today is to identify issues for further analysis, I would like to suggest a careful look at the market economics that drive the choices people make between fuels. For example, we have recently noticed that in many of the major industrial centers of the United States, including those on the West Coast, the price of natural gas for industrial users is equal to, or in some cases higher than, residual fuel oil. This is a

significant change from historic patterns in which gas was generally much cheaper due to FPC price regulations. What we are seeing now is evidence that some large industrial users are shifting from natural gas to fuel oil, not because of the threat of gas curtailments, but because of economics. The threat of curtailments in recent years did cause some users to install dual fuel capabilities in their boilers so they could burn either fuel if necessary. Once they have the dual fuel capability, they can shift fuels on a short-term basis based on the cost and availability of oil and gas at any point in time. We expect this trend to continue in the near/medium term, with both industrial and utility users shifting from gas to oil. This movement will be accelerated by anticipated Federal legislation prohibiting natural gas use for most electricity generation.

In the longer run, we expect to see fuel shifts toward coal in the industrial and utility markets. Based on our current perceptions, it appears that coal will be the economically preferred fuel for most new industrial or utility boilers in the future, including the cost of Clean Air Act compliance. However, there is a great deal of uncertainty regarding future fuel prices and the specific requirements of state Clean Air Act implementation plans.

Any attempt to assess future energy demands must recognize the major uncertainties that we face, especially in both State and Federal policies that impact energy production and use. I have already mentioned Clean Air Act implementation in terms of its possible impact on coal use. It will also have an important impact on the use of oil as a fuel, especially in California. Many facilities on the West Coast today burn residual fuel oil that has sulfur contents higher than may be allowed in the future. Changes in sulfur content limitations will change the market competitiveness of both high- and low-sulfur oils and has implications for the industry's ability to refine sufficient amounts of low-sulfur residual fuel on the West Coast. If low-sulfur residual fuel is in short supply, this may increase industrial demand for natural gas and reverse the recent trends toward oil in the industrial sector.

Natural gas availability is also an issue in California today. Current sources of gas are declining and will have to be augmented by developing new gas resources, importing LNG, and increasing imports from Mexico. The level of gas supply ultimately available will influence the level of demand for gas and, through market substitution effects, demand for other fuels.

Another major uncertainty, well documented in other papers at this conference, is our declining expectation for electricity demand. A major part of this uncertainty is related to expectations for energy conservation and solar energy. Most energy analysts expect major contributions from conservation and solar energy near the end of the century, but there is great disagreement about earlier periods. Part of the difficulty is how to do analysis of something we're not used to doing. We do not have a lot of experience or a good track record in doing analysis of energy conservation or applications of new techniques such as solar energy. There is also great uncertainty about

costs and the development of new equipment and materials. Thus, it is not a question of whether we like it or not, or want it or not, it is a question of how effective we can be today in realistically analyzing the potential in these two important areas.

A final uncertainty that can impact the outlook for energy demand are policy decisions on energy supplies, such as nuclear and LNG. The level of energy supplies and the form in which it is available, will flow through to the demand for energy and impact peoples' choices for fuels. I have already discussed this in terms of gas versus oil. Likewise, the availability and relative price of electricity, partly determined by decisions about siting nuclear and coal-fired power plants, will influence future demands for both electricity and competing energy forms.

ENERGY SUPPLY

Assuming the preceding is a reasonable view of potential energy demands, what are some of the supply options that may be available to us in this century? As noted earlier, the major source of energy in California will continue to be oil and gas, contributing over half of the West Coast's primary energy in 1990. Thus, while the most interesting issues for policy in California today are coal, nuclear, solar, and other alternatives, we also have to think about developing the extensive oil and gas resources that are potentially available in California, especially offshore. In the near to medium term, policy choices related to oil and gas may be more leveraging than others and it is appropriate to talk about them even though we are at a coal conference. Table III indicates a possible scenario for oil supply in PADD V consistent with the assumptions and demand estimates shown in Tables I and II. PADD V oil production is going to be rising fairly sharply within the next several years, but nearly all the increase is outside California, primarily the North Slope of Alaska. California production is relatively flat including an assumed high level of production from the Elk Hills Petroleum Reserve. We see imports dropping dramatically from what they were before the start-up of the Trans-Alaska Pipeline. The important point, however, is that there will still be imports of oil for the West Coast because of the need for the low-sulfur oil that I referred to earlier. The expected flow of imports is essentially all low-sulfur crude oil, which can be readily refined to low-sulfur residual fuels that meet California limits on sulfur content. Due partly to the peculiarities of existing Federal price control regulations, the economics of importing low-sulfur crude oil are superior to the economics of building additional desulfurization capacity for high-sulfur California or Alaskan crude oil.

Given our earlier assumptions about oil demand, there is a potential excess oil availability on the West Coast that could be shipped east of the Rocky Mountains to PADDs I thru IV. It is important to note having that oil available on the West Coast is not a supply "surplus" in national terms. The continuing need for imported oil on the East and Gulf Coasts is far in excess of total West Coast oil production. The real need is for economic transportation systems to move the oil eastward.

In Table IV we see California production of natural gas rising based on a number of assumptions about the leasing of offshore areas for oil and gas exploration and success. We expect Alaskan gas supply to increase even faster assuming that the pipeline system to bring the North Slope gas to the lower 48 is completed by the mid-1980s. Most of that gas will be shipped to the eastern part of the United States and a portion will move to California. While the availability of gas on the West Coast is increasing rapidly, demand is increasing slightly over this time period, so there's still a need for large supplies of natural gas from PADDs I - IV and imports. The question is where is that going to come from? Today most of it comes via interstate pipelines from Texas and New Mexico. However, this traditional supply is declining and will probably not be able to fill the need, especially in California. Thus, we expect it to be augmented by new supplies of gas from Alaska, Mexico, Canada, some LNG, and possibly some synthetic gas. I believe that the indicated need for gas can be met, but it cannot be met easily. It will also be expensive. It is going to require aggressive actions by the gas utilities and by policy makers in California to insure that the necessary quantity of gas is available.

To return now to the subject of today's meeting - coal, I would like to repeat my view that coal supply is not an issue for California. There is certainly plenty of coal resources available nearby. The ability to mine and transport the coal to California is there. The real question is coal demand. Will California want to use coal, especially for electricity generation? That's the policy question and reason for this conference. But this issue can only be addressed in terms of its potential impact on implementation of the Clean Air Act. Can coal station emissions be controlled in an effective and adequate way? What will be the impact of coal fired power plants on ambient air quality? Answers to these questions and resulting policy choices about Clean Air Act implementation will largely determine the level of coal use.

We must also consider policy choices about other fuels. In earlier sessions of the conference, people discussed the need for electricity and the trade off between coal and nuclear in providing new base load capacity. If the choice is to forego (or to limit) nuclear generating capacity, then there is that much more need for other sources of electricity, and coal is the most likely choice, since it appears to be the most cost effective alternative for producing large amounts of base load capacity. But once again we face the uncertainty of whether coal can meet our clean air standards and whether they can accommodate the large-scale coal use that some have suggested. If large-scale coal use turns out to be environmentally unacceptable, then the pressure will return once again to oil and natural gas for electricity generation. Those are two fuels which, I expect, are not only going to be scarce fuels but very expensive fuels. Most incremental oil supplies for California are going to come from outside the state and will be expensive. Incremental gas supplies will also come primarily from outside the state. As we look at the possible options: LNG has siting problems, Mexican gas

has pricing problems, Canadian gas has political problems, Alaskan gas has transportation problems, and synthetic gas has cost and regulatory problems. All these incremental sources have problems that may translate into higher costs, and the average cost of gas for California is probably going to be much higher than it is today.

CONCLUSIONS

In summary, California energy policy makers face a number of critical choices during the next few years that will impact both energy supply and energy demand over several decades. The pivotal choices, and those with greatest long range impact, are probably those decisions related to electric generating capacity, especially the choice of building nuclear and/or coal fired power plants. Decisions that result in inadequate new generating capacity will probably result in increased demand for oil and gas, fuels that are likely to be both scarce and expensive in coming decades. While it is clear that we must work to develop solar, geothermal, and other renewable forms of energy as rapidly as possible, most observers believe that these

sources are not capable of meeting all of our incremental and replacement energy needs during this century. While new forms of energy must be vigorously pursued, prudent planners and policy makers cannot assume good luck in their development. The long-run transition to renewable energy requires vigorous development of fossil fuel resources and electricity generation from coal and/or nuclear energy to see us through the next several decades. To be truly effective, California energy policies need to balance these near-term and long-term goals, while recognizing the many uncertainties and unknowns that are involved in attempting to make any assessment about the future. Finally, California energy policies will be most effective if they reflect both the national and international energy situation. California is no more capable than any other states of "going it alone" on energy policy. We are major importers of both crude oil and natural gas and will continue to be so in the future. It is important that California develop policies that are both pragmatic and responsible in meeting the needs of her own citizens while reflecting the national and international nature of energy problems.

REPRODUCIBILITY OF THE ORIGINAL PAGE IS POOR
 Table I. Potential Energy Demand in PADD V, By Market (10¹⁵ BTU)

Market	1972	1976	1980	1985	1990	Average Annual Growth Rate 1976 - 1990
Household & Commercial	2.1	2.1	2.4	2.8	3.2	3.0%
Industrial	2.1	2.1	2.3	2.6	3.0	2.7
Transportation	3.0	3.2	3.5	3.6	3.7	1.1
Market Demand	7.2	7.3	8.2	9.0	9.9	2.2
Electricity Conversion Losses	2.0	2.2	2.7	3.4	4.1	4.5
Primary Energy Demand*	9.2	9.5	10.9	12.4	14.0	2.8

*All columns may not add due to rounding.

Table II. Potential Energy Consumption in PADD V, By Fuel (10¹⁵ BTU)

Fuel	1972	1976	1980	1985	1990	Average Annual Growth Rate 1976 - 1990
Oil	4.4	4.8	5.5	5.8	5.9	1.5%
Gas	2.9	2.4	2.4	2.5	2.7	0.7
Coal	0.2	0.4	0.7	1.1	1.4	8.8
Nuclear	0.06	0.1	0.4	0.8	1.5	21.4
Hydro	1.6	1.7	1.8	1.9	2.0	1.2
Other	0.03	0.1	0.1	0.3	0.5	13.5
Total Primary Energy	9.2	9.5	10.9	12.4	14.0	2.8

Table III. Potential Oil Supply* in PADD V

Supply	(MBD)	1976	1980	1985	1990
Domestic Production (Of Which California)		1.1 (0.9)	2.3 (1.0)	2.9 (1.0)	3.1 (1.0)
Imports		1.1	0.5	0.5	0.5
Other		0.2	0.2	0.2	0.2
Total Supply		2.4	3.0	3.6	3.8
PADD V Consumption and Product Exports		2.4	2.7	2.9	3.0
Shipments to PADD I-IV (Including Products)		-0-	0.3	0.7	0.8

*Includes lease condensate and natural gas liquids.

Table IV. Potential Natural Gas Supply in PADD V (BCF/D)

Supply	1976	1980	1985	1990
California	1.0	1.1	1.4	1.7
Alaska	0.5	0.7	2.9	5.2
Total	1.5	1.8	4.3	6.9
Less Shipments Out	0.1	0.1	1.8	3.1
PADD V Avails	1.4	1.7	2.5	3.8
PADD V Demand	6.5	6.4	6.8	7.2
Gas Requirements From PADD I-IV & Imports	5.1	4.7	4.3	3.4

10/17/78
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Session II: FUTURE ENERGY DEMANDS IN CALIFORNIA

Session Cochairmen: James Sweeney (Stanford University)
Elliott Framan (JPL)

Panel Members: Mike Jones (CEC)
Nolan Daines (PG&E)
Edward Griffith (ARCO)

OPEN DISCUSSION BY ATTENDEES

JAMES SWEENEY:

This afternoon we have heard papers concerning the future energy demands of California, coal's role in meeting California's energy needs and uncertainties about the supplies of alternative fuels. What was not brought up, but I think is quite important for the subsequent workshop to consider, are uncertainties in analysis. The responsiveness of energy demand to prices is much debated and is still not well understood. The elasticities of demand for energy as an aggregate is not understood fully. There is a consensus possibly that demand elasticity is in the order of maybe .2 to .6, but that is a 3 to 1 range, and thus not exactly a tight consensus. There is major uncertainty about the possibilities for interfuel substitution--to what extent can one conventional fuel be substituted for another. These are some of the uncertainties that I see. I would like to now open the floor for questions and discussions. In so doing, I request that you not start a debate about the "right" answers, but rather aim at developing an understanding of the determinates of coal demand, of the factors which will influence the demand for coal, and particularly of those uncertainties which will be important to resolve in the subsequent workshop to be held this fall.

GREG SEBAY:

I'm representing the Burbank Municipal Utility. I think some of

the uncertainties in forecasting energy demand for California and indirectly the need for coal, can be understood a little better if you realize that the State or the government has a large hand in deciding what that demand will be. In other words, energy demand in California is not just a matter of forecasting something outside us, but really a matter of choosing what kind of state you want to have. To use an example close to home, we have several redevelopment projects in Burbank. If the City Council decided that it wanted the city to maintain more or less the same level of commercial and industrial activity, if it wanted to zone for a certain, say "single family only", that would imply one kind of energy demand, and once we made that decision, we would then in effect determine to a large degree what the energy demand would be. On the other hand, if we want to expand to a great extent the industrial and commercial base, then that implies a much higher energy demand and our policies would have to be consistent with that. So it's really just a thought I want to throw out to the panel. The demand for energy and indirectly a demand for coal really depends on what kind of state you want California to be 10 or 20 years from now.

MIKE JONES:

As I alluded to earlier in my discussion, the Commission has a really major role in energy conservation in the State, and was given by the legislature mandatory standards to implement building appliance conservation. I would concur that, to a large extent, California, as a leader in this area, is continuing to play an active role. Certainly my remarks are consistent with the statement that conservation is being looked at as a very major instrument in determining what we need to provide in the way of future electric generation capabilities for the State.

DONNA LIVIROTTO:

I have a question for Mr. Jones or Mr. Daines. I have talked a lot about electric demands. Is anyone looking at natural gas demands?

I realize that you are not on the gas side of the house of PG&E, but presumably coal gasification, for instance, is an option. Is there a demand for a medium BTU or a low BTU gasified coal? Is that being looked at as an option?

NOLAN DAINES:

You're right that I'm not on the gas side of the house of PG&E. We have several projects that are being looked at for supplying gas needs. Our gas supply has been reducing because of allocations by the Federal Regulatory Commission, to east of California. Our supply from El Paso Natural Gas has been on the decline. Another major supply is from within California, producers from California, and that is not increasing, but projected to decline also. Our major supply is from Canada, presently from Alberta, though that's not declining, at present, our permits do begin to expire later in the 1980's. And so, forecasting our needs, we need large amounts of gas to replace that which is declining in its supply, as well as perhaps some growth in demand for natural gas. The various projects we have under way include the much debated LNG terminal or a supply that would use that terminal from the Cook Inlet of Alaska and also from Indonesia. We are a participant in the North Slope of Alaska pipeline to bring gas into the United States, some of which would come to California. We have exploration going on in the Rocky Mountain area to find additional gas; but, getting to your question about use of coal for gas, yes, that is another option that we are looking at. Currently, we are investigating the possibility of going into an LNG or a substitute natural gas project to supply at least a small part of our future needs for gas.

MIKE JONES:

I could add just a little bit to that. Unfortunately, I'm on the other side too. The Commission is involved in a major proceeding on natural gas supply and demand with the PUC oriented towards

determining the need for an LNG facility in the State. I would suggest to any of you that are interested that there's a vast amount of material available from that proceeding, specifically on demand forecasting and supply. Generally speaking, there is some real optimism that new gas sources will be available and on the other side that natural gas demands should remain relatively constant. A number of things are happening external to the State that I'm not really familiar enough to comment on. One such item that was pointed out to me yesterday, when I asked a similar question, was the conversion in Texas of approximately 20,000 megawatts of natural gas-fired electric generation capacity over the next five or so years to lignite which could have a beneficial supply effect for California.

BOB SHIPP:

I'm with the Energy Commission. I'd like to ask Mr. Griffith, and I guess Jim Sweeney, since he's an expert, how you recommend we account for conservation and potential conservation in future forecast of demand, especially in the commercial and industrial sections where we don't have very good end use information to make State policy. I would be particularly interested, Ed, if you could describe how in ARCO's forecast you dealt with conservation, potentially either in response to price increases or mandating actions by the State in terms of conservation standards. Jim, in terms of the work you've done in forecasting, how would you recommend dealing with the commercial industrial section in end-use forecasting.

ED GRIFFITH:

To account for conservation in a specific way is extremely difficult. The work we've done we have not dealt with specifically on a product by product, process by process, or industry by industry basis. We have attempted to do it in a fairly gross way, which is to make some assumptions about overall improvements in the use of energy efficiency

in relation to economic activity. Now that's clearly, in the long run, not a satisfactory way to make the analysis. It's the first attempt and a fairly crude one. I have seen some other analyses done by people where they've attempted to take specific line count, by economic activity, one at a time, such as making steel, or producing aluminum, or making cars, whatever it is, and trying to apply some expert judgement to the change that might occur in the amount of energy per unit of output. If you can talk to engineering people in specific industries in the State of California that follow such things, they may be able to provide you some expert guidance on the potential for improvement because of technology change or just more efficient use. But it's a tough nut certainly. One of the difficulties on conservation is that there are certain kinds of energy conservation that are easy, that people do when the price goes up. A lot of that's been already done. You do from a process of better husbandry and more efficient use and better care, to the situation where you have a need for what are effectively investments, to create technology change and to construct more modern facilities that will use energy more efficiently. I think that the only way you're going to get at that is to go to an industry by industry basis. Roger Sand of Carnegie Institute is now starting to do a major project on that area and he would be someone worth talking to

JAMES SWEENEY:

I'd like to first comment that I don't like the word conservation. I like the concept but it's a very misleading word, since it can include so many separate issues. What we mean normally by energy conservation is a direct or indirect substitution of other scarce factors of production for energy which is itself a scarce factor. Many times, "conservation" means substituting capital and labor for energy, or increasing the proportions of capital and labor and decreasing the proportions of energy as inputs to a given process. In other cases, "conservation" may imply changes in the output from industrial processes, or changes in the activities people are able to pursue.

I'd like to suggest there are two types of "conservation."
One is simply the freely chosen response of firms and individuals to increasing price of energy; firms and individuals find it in their own interest to reduce the consumption of energy when its price goes up relative to the prices of the other inputs. The second type of conservation gets most of the policy attention. This is mandated conservation: measures that force individuals or firms to change the way they use energy or change production processes.

To model the first type, the price driven conservation, there's a number of alternative approaches. First is engineering analysis in which one examines which activities can be expected to change use of energy. The total change is estimated by adding up overall such activities. More commonly though, have been the econometrics studies which fit a very simple functional form relating the demand for energy to variables such as economic activity and the price of energy. Using this historical data, one can estimate coefficients describing how the demand for energy has been influenced in the past by prices. Then, using heroic assumptions, one can extrapolate to the future (often out of the range of the data that have been observed), to obtain some estimates.

A far more dependable approach is to develop structural models. If you want to examine both types of conservation, price induced and policy mandated, then you must understand the structure of energy demand. You can't get away with a simple reduced form of econometrics: you would get laughed out of the room. There has been some work in developing structural models. For example Eric Hirst has been conducting excellent work at Oak Ridge National Laboratory where he has tried to model in detail the processes by which energy is used in the residential sector, separately modeling the formation of the capital stock of the energy using equipment and the rate of utilization of that stock. This approach is useful towards a further understanding of mandated efficiency standards. I've done some work in modeling the transportation section. We now have average efficiency standards for new automobiles so we eliminated most of the price elasticity of demand for gasoline. The greatest impact of higher

prices on gasoline demand has been through influencing the efficiency of the capital stock of automobiles. Now we have a law, with sufficient incentives which mandates what the efficiency of new cars will be, on the average. Thus, developing structural models for auto use of gasoline is somewhat easier than it would be in other sectors.

UNIDENTIFIED ATTENDEE:

One quick question that probably deserves a quicker answer. Can I poll each of the panelists to answer the following question, yes or no, if you can do it. Is the zero energy growths scenario for California credible or incredible from your perspective.

JAMES SWEENEY:

Yes, it's credible at a high cost. But is it worth this cost?

PANEL MEMBER:

I'd say it's extremely unlikely, as I don't think the people of California would be willing to pay the cost.

PANEL MEMBER:

In one word, incredible.

PANEL MEMBER:

I certainly don't see it happening based on current policy, no.

JOHN GEESMAN:

I'm with the California Citizen Action Group. In light of the dominance of Indonesian fuel oil imports on the West Coast, I'd like to ask each of the panelists if they envision the sort of pressure from either State or Federal government to utilize the Alaskan crude, which might motivate West Coast refiners to take a more aggressive approach in expanding desulfurization capacity in their refineries.

EDWARD GRIFFITH:

Let's make a comment that part of the economic drive that came out of that situation relates to the price regulation that exists at the Federal level. I doubt that the Federal government would have any great pride in regulating to the extent that the Alaskan oil, that remains available on the West Coast, can be made available to the rest of the nation. It still becomes a domestic energy resource that's used extensively. One can argue about relative economics but if you really want to get into it, the economic solution, of course, is to ship that oil to Japan as an exchange for Middle Eastern oil, which the Japanese have under contract. It can then be shipped to the East Coast of the United States. The total transportation cost of doing that and the total cost to the Nation of using the Alaskan oil would be less than what we are doing today; which is bringing it down to the West Coast and trying to figure some way to get it to the East. It's this kind of perversion that comes from the current policy of not allowing exports of Alaskan oil, plus the specifics of the way the price regulations happen to work. That creates the situation where we are going to continue to have imports on the West Coast while we have domestic oil that is available. I have no way to know whether their policy choices about that might change, although my personal feeling is that they probably won't.

NOLAN DAINES:

Currently, we have a fuel supply coming from both sources, the Indonesian supply and the oil companies which remove sulphur from the oil. From the utilities point of view, I think we would take whatever is least expensive for the utility. It's pretty much a decision that the oil company would have to make on the basis of what Mr. Griffith just described.

EDWARD GRIFFITH:

I should point out there is plenty of refining capacity elsewhere in the states to handle that high sulphur crude. It's only a problem in the West.

MIKE JONES:

Just one comment. I think the current Federal pricing policy has been blamed by many for not providing the incentives to provide the desulphurization capability. I can't really say what the Federal policy is going to be, but it is extremely important to providing additional desulphurization capability. I could be wrong, but I believe the desulphurization capability in the State is actually being fully utilized at this time.

EDWARD GRIFFITH:

I don't know, but there is another piece to that. That is, the expectation of the emission requirements for oil be made more stringent in the future in some of the air basins. In that way, we'll compound the problem from where it is today.

JAMES SWEENEY:

I'll pass, in that I have nothing to add.

NANCY BOXER:

I'm from Planning Research Corporation. I'd like to address this question to Mr. Griffith, who said there was no coal supply problem and also because he is an employee of the organization which, I believe holds some resources. My question is, do you believe that the current demand projections and price projections justify increased investment in coal production and is your answer different for expansion of old mines as for opening new mines, say for the mid-or-late 1980's?

EDWARD GRIFFITH:

Correctly identified as a company that not only produces oil and gas, but since December 1977, is also a coal producer in the West, the obvious answer to whether it makes sense to invest in coal is yes. That's also based on other views and just my understanding of the national and world energy situation. I think that not only California, but the whole country is facing a situation where additional coal will be required as one of the fuels available to us on a very large scale. There are very massive resources of

coal in this country at today's relative economics that are available and will need to be used. Of course, the national policy reflects that, in terms of whether they want to expand old mines or open new ones, I have no idea. I can't answer that specific question.

SESSION III

**ENVIRONMENTAL ASPECTS OF COAL USE
FOR CALIFORNIA**

N79-27604

POSSIBLE ENVIRONMENTAL EFFECTS OF INCREASED
COAL USE IN CALIFORNIA

Dwight L. Carey

Southern California Energy Committee Chair
Sierra Club

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ABSTRACT

If coal is to be utilized in California it must be made compatible with the State's drive toward restoring environmental quality. The impacts resulting from coal's mining and transportation, or from water consumption, water quality degradation and electric transmission line routing can probably be adequately mitigated through strong and early planning efforts, the use of improved control and process technologies, and sincere utility commitment. The socioeconomic impacts may prove somewhat more difficult to satisfactorily mitigate. Of greatest concern is adequate control of generated air pollutants and disposal of solid and liquid wastes since acceptable technologies or handling techniques have yet to be conclusively demonstrated.

I. INTRODUCTION

Coal definitely has the reputation of being a "dirty fuel," and, in many cases, that reputation is not without good reason. We need not look too far into the past to remember scenes of skies darkened by clouds of ash from coal-fired power plants. Things have changed somewhat in the recent past, for there has been a lot of improvement in technologies, in regulations and in commitments that have resulted in a significant clean-up of the newer facilities. If one looks at the future with some optimism there may indeed be even greater chance of cleaner, less environmentally destructive coal-burning facilities. In fact, there have been statements already that that future is now, that this "clean coal" future is already available. Most of the other papers in these proceedings be discussing these "clean" technologies, and this paper will leave it to those proponents who know more about the technologies to attempt to demonstrate that they are in actuality now feasible. It is our belief, however, that no matter how it is undertaken coal utilization is going to result in a large number of environmental impacts, many of which cannot be adequately mitigated through the use of any type of advanced technology. This paper will mention many of these environmental impacts, specifically those which may result from an effort to utilize coal in California.

It has been pointed out that California does not have any economic coal reserves. This does not change the fact that coal mining, wherever it occurs, will cause detrimental environmental effects which should be evaluated. California cannot externalize the environmental disbenefits of other segments of the fuel cycle by discussing only the impact of coal use within the state. This is just as one must assess the environmental and economic impacts of the entire fuel cycle of any other generation technology. Thus we have need to consider the impacts resulting not only from the utilization of coal but from its mining and transportation as well.

II. THE MINING SEGMENT

Impacts can occur from either subsurface or surface mining, and they can be large-scale impacts. The size of today's large coal mines can range from one to three million tons per year for individual underground mines, to nearly ten million tons per year for the very large surface mines. These large mines require a tremendous number of workers, both in the mine itself and in the beneficial on cycle. The introduction of these new workers can result in tremendous disturbances to the local socioeconomic system, a system which is often unstable enough in already established districts, but which can be essentially nonexistent in some of the remote, unpopulated areas where new mines may be opening in the near future. These small rural economies can expect a population influx that would completely change their entire socioeconomic system.

Surface mining will require a direct and substantial commitment of land to a use whose impacts are usually not totally reversible. Landscape modifications, surface and ground water disturbances and pollution, and significant wildlife and vegetation disruptions can result. Ecological network alterations can require decades to reestablish, and even with restoration we are not always convinced that complete reestablishment is possible. In subsurface mining, subsidence of the surface and disruption to ground water are both significant impacts. Since only

approximately fifty percent of the coal in any seam mined underground can be recovered, a lot of that coal resource is left in the ground. Significant water pollution can also occur from underground mining. Underground mining is still one of the most hazardous occupations in the United States today. The beneficiation process that takes place at the mine can produce large quantities of solid waste. Sometimes ten to twenty percent or more of the mined product has to be discarded. These discarded wastes, as well as the beneficiation process itself, could lead to additional air and water pollution.

III. THE TRANSPORTATION SEGMENT

The over-water movement of coal, from either Alaska or Washington via seagoing barges, has been considered as a viable coal transportation option. Any establishment of a large seagoing traffic in coal could result in the need for additional port facilities and the destruction of coastal resources.

The environmental impacts that may result from the use of a coal slurry system are generally more benign. Some air quality degradation will result from the preparation process. The water that is used in the slurry is not consumed in the slurry and can be reclaimed and used at the power plant. This would, however, result in interbasin or interstate water transfers, which are likely to be politically, if not environmentally, significant. Slurry transportation does result in a higher energy cost in that the residual water left in the coal after drying does result in a one to two percent decrease in the amount of available heat from the burning process. Coal slurries, of course, do have a fixed throughput which allows very little flexibility in altering the amount of coal delivered to the utilization site. Construction impacts are generally minimal in that from two to six weeks from the first impact the land can be restored (or at least attempted to be restored) to its original condition. Coal slurries are also generally safe.

Coal transportation, on the other hand, can result in a much larger number of safety and environmental impacts. As an advantage, it does have a variable throughput. It does not lose heat to the combustion process through the addition of water, but requires energy to move those locomotives, either electric or diesel. Relatively large amounts of air pollution can result from coal transport by rail via losses in transit. The movement of a large quantity of coal by rail can lead to quite significant social impacts to the areas through

which it runs. A 1000 Mw coal plant will probably require about 300 unit trains per year to supply it with coal. That is 600 trips through every town along the route, a tremendous impact to any local rail community.

IV. THE UTILIZATION SEGMENT

The list of the possible impacts from coal utilization could be enormous, so herein will be described only those considered most significant. These most conveniently fall into the categories of impacts to air quality, water quality and supply, socioeconomic systems and land use. Since others in these proceedings will be specifically discussing the impacts to and constraints of air quality and water quality and supply, these topics will be only lightly touched upon below.

Possible degradation to air quality has so far received the most attention, and it appears that this is rightfully so, as it is probably the most critical and yet undefinable constraint. It must be said that we cannot afford to compromise California's progress toward achieving compliance with the Clean Air Act and its amendments as the price of meeting a portion of the State's energy demand with coal, and that it appears necessary to have at a minimum those recently described advanced control technologies and processes correctly incorporated into any California coal-fired power plant before it will be capable of meeting our air standards.

Water is a constraint to any large power project and coal, of course, is no exception. We do believe that the State's existing policy correctly places the consumptive use of fresh water by power generation facilities as the lowest possible priority, and that this does restrict the alternatives that coal-fired power plants can utilize for their water.

The term "land use" impacts is used here as a catch-all phrase to describe any impact to land-based systems. For example, a 1000 Mw power plant will probably utilize anywhere from one to two thousand acres for structures, transportation facilities, coal storage, water storage and liquid and solid waste storage or disposal over the life of the plant. Many of these are going to be irreversible land commitments in that restoration is going to be a very difficult task. Tremendous quantities of solid and liquid wastes are going to have to be disposed of, and, at present, the techniques utilized to dispose of these wastes are very crude. As an example, the current technology for

liquid waste disposal is in open storage ponds. Most biologic communities can be tremendously affected by not only the siting of a power plant itself, but by the increased activity of man in the surrounding environment. Impacts resulting from the emission of trace elements is an often overlooked and poorly understood result of coal burning. The visual impacts of the project, with its gas stacks over 700 feet high, along with the plant itself, the storage ponds, cooling towers, transmission lines, etc., can be tremendous. Finally, there are the possible conflicts with existing and planned other land uses. For example, the desert wilderness area in California is being evaluated by the BLM for wilderness areas and there are plans for a Mojave national park.

Some very direct socioeconomic impacts result from the construction of a coal-fired power plant in a generally remote area. The primary concern is over the boom and bust cycle of intense employment in construction activities, followed by a very reduced employment opportunity in the actual operation of the plant. Large plants mean, of course, large booms and large busts. One possible mitigation option may be to try to limit the size of these units to smaller, more moderately-sized facilities, thus limiting the size of the amplitude of the cycle. We could also then possibly try to locate these facilities closer to our load centers. This system would allow us to tailor the construction of new plants to better meet our incremental power needs. With smaller plants we would also be able to more rapidly utilize advanced coal combustion technology or methods, as these advanced processes became available.

V. CONCLUSIONS

We believe that improved coal utilization and pollution control technologies can help to alleviate impacts, but technology alone cannot solve all of the anticipated impacts. The new technologies cannot solve the socioeconomic impacts, and they cannot completely solve the air and water quality impacts. Good planning can help to alleviate many impacts, specifically those arising from coal mining and transportation, from water consumption and water quality degradation, or from electric transmission line routing. The staged construction of relatively moderate sized facilities can help to alleviate socioeconomic impacts but cannot eliminate them. Our primary concern is that the potential problems of air quality degradation and waste disposal as solutions to these problems have not yet been adequately developed or tested.

In summary, if coal is to be utilized in California, it must prove itself to be an environmentally viable energy source, as must any other energy source. All effects of the entire coal fuel cycle must be considered and weighed against the perceived benefits, and these costs and benefits compared with other alternative generating sources. Coal utilization in California, or anywhere else, does have inherent in it a large number of environmental impacts which need to be mitigated before it can be rationally used. Although a maximum diversity in our energy production mix can assist us in meeting California's energy needs, we cannot rely on going with coal as a big way for it is not a panacea for our problems. Coal utilization can only be considered as an intermediate term measure, necessary only to provide electric power until such time as other advanced systems utilizing renewable resources are fully capable of supplying our energy requirements. We cannot expect coal to be both clean and cheap, nor can we afford to utilize anything but clean coal.

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AIR QUALITY AS A CONSTRAINT TO THE USE
OF COAL IN CALIFORNIA

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Thomas C. Austin

California Air Resources Board
Sacramento, California

ABSTRACT

Considering the air quality problems which exist in California without the combustion of coal for electric power generation, many have felt that any significant use of coal in the state would be inconceivable. However, recent developments in emission control technology have made it possible to burn coal in certain applications with significantly lower emissions than currently result from the use of fuel oil.

Low-NOx burners, wet scrubbing systems, baghouses and ammonia injection systems are feasible for use on large combustion sources such as utility boilers. These devices, used in combination with coal handling techniques which minimize fugitive dust and coal transportation related emissions, could enable new power plants and large industrial boilers to burn coal without the adverse air quality impacts for which coal has become notorious.

I. INTRODUCTION

Although coal has long been recognized as the most significant fossil fuel energy resource in the United States, it was not until after the Arab oil embargo of 1973 that oil and gas began to be considered as unacceptable fuels for use in large, fuel-intensive facilities such as utility boilers. Prior to the embargo, the federal government, through the Environmental Protection Agency, actually encouraged the conversion of coal-fired utility boilers to oil-fired operations as a relatively inexpensive technique for achieving substantial emission reductions.

Air Quality problems have been a significant factor affecting the design of power plants within the state and throughout California power plants have generally burned natural gas to the maximum extent possible. The use of fuel oil is limited by the South Coast Air Quality Management District (SCAQMD) to fuels containing no more than 0.25 percent sulfur. Other metropolitan APCD's limit the sulfur content of fuel oil to 0.5 percent.

Despite the fact that large coal-fired combustion sources have been considered to be generally unacceptable in California, it is now clearly imprudent to plan for the use of oil or gas in any new, baseload power plants. The principal options left for California for balancing the electric power supply and demand are conservation,

cogeneration, hydro, geothermal, nuclear, and coal. The California Air Resources Board (ARB) has not taken a position regarding the construction of new hydro or nuclear power plants since the principal environmental risks associated with these facilities are outside the purview of the ARB and have therefore not been evaluated. Of the remainder, conservation (including decentralized solar), cogeneration and geothermal are viewed as generally preferable. However, to the extent that these alternatives are not available to satisfy electric power demand in California, the carefully regulated use of coal can be acceptable from an air quality perspective.

II. CALIFORNIA AIR QUALITY

Basin-like topography, frequent atmospheric temperature inversions and a high concentration of vehicles and industry have caused serious air pollution problems in California's three largest metropolitan areas and in the San Joaquin Valley. None of the state's fourteen air basins, shown in Figure 1, are currently free from violations of at least one ambient air quality standard. The ambient air quality standards which are related to the combustion of fossil fuels are shown in Table 1.

Table 2 summarizes the highest pollutant concentrations recorded during 1977. Oxidant (primarily ozone), a substance formed during a photochemical reaction between hydrocarbon emissions and oxides of nitrogen emissions, is the most pervasive air pollutant in California. As has always been the case, the highest oxidant level was recorded in the South Coast Air Basin. The basin with next highest oxidant concentration was the Southeast Desert, where the South Coast Air Basin air mass is transported by the prevailing west-to-east wind flow. Peak oxidant levels in the South Central Coast and San Diego Air Basins can also be affected by South Coast Air Basin emissions. However, the air quality problems in both of these basins are substantially affected by locally generated emissions. Although oxidant standard violations were recorded in each basin where measurements were made, the violations which have occurred downwind of major urban areas may be eliminated through the control measures applied in the urban areas provided adequate NOx control is achieved.

High Total Suspended Particulate matter (TSP) levels are caused by any or all of three different conditions: (1) Industrial sources of particulate emissions which are not equipped with adequate controls, (2) vehicular and industrial sources whose emissions of hydrocarbons, nitrogen oxides, and sulfur oxides are chemically transformed into "secondary" particulates such as organic aerosol, nitrate and sulfate, and (3) windblown dust. Within big air basins with high oxidant levels such as the South Coast Air Basin and the San Joaquin Valley Air Basin, secondary particulate is a very major problem.

In many rural areas windblown dust is the major problem. The adverse health effects of windblown dust, because of its large particle sizes, are generally far less significant than for equal concentrations of anthropogenic particulate emissions of either the direct or "secondary" variety. For this reason and for the practical problems associated with the control of windblown dust, the EPA does not consider levels in excess of the ambient air quality standards to be violations if they are caused by windblown dust.

SO₂ and sulfate concentrations are a serious problem in both the South Coast and San Joaquin Valley Air Basins. The South Central Coast and the San Diego County Air Basins have also experienced violations of the standard for sulfate. No other basins have been determined to have problems at this time.

Violation of the ambient air quality standard for nitrogen dioxide were recorded in the South Coast, South Central Coast, Southeast Desert, San Diego, and San Francisco Bay Area air basins. As has historically been the case the NO₂ levels recorded in the South coast Air Basin were almost double those recorded elsewhere.

In summary, California's fourteen air basins can be segregated into three categories from an air quality perspective considering only those pollutants significantly related to the combustion of fossil fuels.

Six basins, South Coast, South Central Coast, San Diego, San Francisco Bay Area, San Joaquin Valley and the Sacramento Valley, experience numerous and severe violations of ambient air quality standards due to both locally generated and

certain of the California air basins experience pollution problems which are not related to fossil fuel combustion. The Lake County and North Coast Air Basins, for example, are experiencing substantial violations of the state's ambient air quality standard for hydrogen sulfide due to the currently inadequately controlled generation of electric power from geothermal steam.

transport related emissions. Two basins, Lake Tahoe and the North Central Coast, experience less frequent and less severe violations, which appear to be primarily the result of locally generated emissions. Six other basins, Southeast Desert, Mountain Counties, Great Basin Valleys, North Coast, Northeast Plateau and Lake County, experience varying levels of air pollution, the highest of which, however, are related to emissions from upwind areas or rural fugitive dust.

III. FUTURE AIR QUALITY

Despite the historical persistence of air quality problems in California, two factors now allow a modicum of optimism regarding future air quality levels. For the first time in history, it is no longer permissible to build major new sources of air pollution, which will exacerbate violations of ambient air quality standards. The Clean Air Act Amendments of 1977 clearly articulate a federal policy of prohibiting the construction of sources of air pollution, which will contribute to existing air quality problems even though these sources may be substantially lower in emissions than similar, existing sources. The fact that a proposed new source has relatively low emissions has in the past been considered an adequate justification for its construction. Federal law now recognizes the obvious fact that degraded public health and welfare are the result of adding "clean" new sources to an overburdened air shed just as increased risks are associated with adding lightweight cargo to an overloaded boat. The federal New Source Review (NSR) program requires that mitigation measures or "trade-offs" sufficient to offset the adverse impact of any major new source of air pollution be a part of new industrial projects. The existence of the federal NSR requirements allows air pollution control agencies to concentrate on existing air problems instead of being forced to deal with unrestrained increases in emissions.

The second factor which is now contributing to a solution to the state's problems is the increased focus on control strategy development at the state and federal level. Historically, local air pollution control agencies have been forced to regulate industrial sources of air pollution with little assistance. The state and, to a lesser extent, the federal government are now recognizing the gross inefficiency associated with requiring local agencies to independently develop and implement regulations for the control of industrial air pollution problems of state-wide or national impact. The basic control strategies needed to reduce emissions from most types of sources are identical whether the source is located in Los Angeles, San Francisco, Bakersfield or Boston. A single control strategy developed at the state or federal level as "model rules" can be given to the numerous local districts for

adoption. These "model rules" can be tailored prior to adoption to the needs of individual districts.

Although the U.S. Environmental Protection Agency is not yet pursuing the model rule concept, EPA does provide "guideline documents" which contain useful information on the emissions control potential for various categories of industrial sources. The guideline documents, useful in developing emission control regulations for both new and existing sources, are supplemented by New Source Performance Standards (NSPS). However, as discussed in greater detail below, the EPA NSPS are usually set at levels which require far less emission control than is technologically feasible and economically reasonable.

A detailed analysis of the emission control measures needed to achieve and maintain the ambient air quality standards throughout California is currently being developed through the combined efforts of the ARB, local governments, and private organizations involved in the Air Quality Maintenance Planning process, which is mandated by the Clean Air Act. The paragraphs which follow give a very brief and general overview of the emerging plans which are expected to be published early in 1979 as the State Implementation Plan (SIP).

The prospects for achieving and attaining the ambient air quality standards in the 1980's are excellent for most of California's basins. Although substantial SO₂, NOx, and particulate matter emission increases could be associated with the shift from natural gas to fuel oil, which is now occurring, work now underway at the ARB indicates that these emissions from major combustion sources can be dramatically reduced through the use of further fuel desulfurization or stack gas scrubbing for SO₂ and particulate emission control, ammonia injection systems for NOx control, and fabric filtration (baghouses) for particulate control. A recent ARB staff report⁽¹⁾ describes how the use of certain of these control techniques applied to thermally enhanced oil recovery operations in the San Joaquin Valley can provide essentially all of the SO₂ control projected to be needed to attain the ambient air quality standards for SO₂ and sulfate and more than half of the NOx control needed to achieve the oxidant standard through a combination of hydrocarbon and NOx control. A draft Air Quality Maintenance Plan⁽²⁾ prepared by the Association of Bay Area Governments outlines the type of hydrocarbon controls which appear to be available to cause attainment for oxidant in the nine counties of the San Francisco Bay Area. Similar controls applied in the South Central Coast, San Diego, North Central Coast and Lake Tahoe air basins may be sufficient to achieve and maintain the

oxidant standard provided growth is carefully managed. Air basins which are experiencing oxidant violations as a result of long-range transport may achieve attainment status provided most feasible hydrocarbon control measures are integrated with appropriate NOx emission controls in upwind areas.

No plan has yet been developed which indicates that the oxidant standard can be achieved in the South Coast Air Basin without economically infeasible control approaches involving the curtailment of current vehicular and industrial activities. However, substantial improvement is already possible and attainment of the standard for NO₂ appears feasible through the NOx reductions expected from the motor vehicle emission standards adopted for future years in combination with the use of ammonia injection systems on large combustion sources and some control of other sources.⁽³⁾ Attainment of the SO₂ and sulfate standards appears to be possible through the application of substantially increased fuel oil, diesel oil, and gasoline desulfurization in combination with control measures on coke calcining kilns, refinery FCC units, and other such sources.⁽⁴⁾

IV. ACCOMMODATION OF COAL IN CALIFORNIA

In areas of California which are projected to achieve and maintain the ambient air quality standards through the implementation of the plans now under development, it will be possible to permit the construction of major new facilities such as coal-fired power plants provided the emissions from such projects are not so great as to cause violations of the standards. If the emissions expected from a coal-fired power plant are calculated to cause an air quality violation, trade-off measures may enable the adverse impact to be mitigated. The need for trade-offs will therefore depend on whether the local air pollution strategy provides for an increment of emissions growth without causing ambient air quality standard violations.

Mitigation measures could also be required if the proposed facility would lead to unacceptable air quality degradation in Prevention of Significant Deterioration (PSD) areas or Air Conservation Areas (ACA's) located downwind. The State's Air Conservation Program⁽⁵⁾, currently under development, is directed at maintaining superior air quality levels (cleaner than required by ambient air quality standards) in areas of important aesthetic significance (e.g. Yosemite, Redwoods National Park, etc.).

The ability for coal-fired power plant proponents to develop emission "trade-off" measures, when necessary, will depend on the quantity of emissions to be offset and the availability of such trade-offs in the

vicinity of the proposed new project. Except for the Greater Metropolitan Los Angeles area, it appears that a substantial quantity of trade-offs will be available from existing power plants. At this time, it appears all feasible power plant emission control measures may not be required to achieve and maintain the ambient air quality standards through most of California. Where all feasible controls are not required, it may be possible for new power plants to be constructed without an increase in electric-power-related emissions through the retrofiting of SO₂, NOx and particulate matter emission controls to existing oil-fired power plants provided that the emissions from the proposed new facility do not exceed the emission reduction potential from existing power plants. In certain areas, however, no trade-offs may be required.

V. EMISSION CONTROL FEASIBILITY

Uncontrolled Emissions - The popular conception regarding the high emission levels associated with coal is born out by a comparison of the "uncontrolled" emissions from coal combustion compared to the combustion of oil and natural gas. As shown in Table 3, NOx, SOx and particulate emissions from coal combustion are substantially greater than from either oil or gas with the particulate emissions from coal exceeding the particulate emissions from oil by a factor of 105 when the oil burned has a sulfur content of 0.5 percent by weight.

The reason for the significant differences between the emissions created from the combustion of coal and other fossil fuels is primarily due to differences in their composition. A typical western coal is 71.43 percent by weight carbon, 1.36 percent by weight nitrogen, 1.00 percent by weight sulfur, 5.05 percent by weight hydrogen, and 8.42 percent by weight ash made up of silica, trace metals and other noncombustible materials. The nitrogen contained in the coal is a contributor to the NOx emission produced during combustion. The ash is the principal source of particulate emissions. While fuel oil may contain as much sulfur as coal, it typically contains only 0.50 percent by weight nitrogen and 0.04 percent by weight noncombustible impurities. Natural gas is typically almost entirely made of methane (93.33 percent by volume and contains only trace quantities of non-hydrocarbon components, such as 0.0009 percent by weight hydrogen sulfide (H₂S), the combustion of which creates the relatively low concentration of SO₂ emissions associated with natural gas combustion. NOx emissions from gas-fired combustion are only created from the reaction between the nitrogen and oxygen contained in the combustion air. No fuel bound nitrogen is present to contribute to the formation of NOx.

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Particulate Emission Controls - Since the particulate emissions from uncontrolled coal combustion are great enough to create a substantial public nuisance, there have been particulate matter controls applied to coal-fired power plants for quite some time. The most common control device is the electrostatic precipitator (ESP), which removes combustion particulates by ducting the stack gases between charged plates. The electrostatic charge applied to the particles results in their migration to the plates where they periodically drop into a collection hopper each time the plates are "rapped" to shake the particles free.

The effectiveness of electrostatic precipitators depends on the surface area of charged plates, particle size, and particle resistivity. While ESPs can be designed for removal efficiencies exceeding 99%, the collection plate area required, and therefore the system cost, increases rapidly above 95% removal efficiency.

Fabric filtration is an alternative to the use of electrostatic precipitators which makes substantially increased particulate emission control feasible. As shown schematically in Figure 2, a baghouse consists of an enclosure containing numerous cylindrical fabric filters ("bags") through which all of the combustion gases are ducted. Sufficient filter area is provided to reduce pressure drop through the baghouse to 1-5 inches of water on typical coal-fired utility boiler applications.⁽⁶⁾ To obtain a combination of high filtration efficiency and low pressure drop, more than 10,000 individual bags might be used for a 500 megawatt coal-fired boiler.

In tests run on full scale coal-fired boilers using fabric filtration, particulate removal efficiencies of 99.84% and 99.91% have been reported⁽⁶⁾. The resultant stack emissions with such efficiencies were recorded at .01 and .005 pounds per million BTU heat input.

SO₂ Emission Controls - Stack gas scrubbing for sulfur dioxide removal has been developed to the point where 95% efficiency can be routinely achieved.⁽⁷⁾ The latest experience in Japan indicates that the reliability of scrubbing systems has been improved to the point where the scrubber is "available" more than 99% of the time.⁽⁷⁾

A number of regenerable and nonregenerable, or "throw away", systems are on the market. A schematic of a simple nonregenerable system incorporating the use of a limestone slurry is shown in Figure 3.

The SO₂ removal mechanism for this type of scrubber involves a reaction between SO₂ and Ca(OH)₂ to form a precipitate of CaSO₃ which is removed from the system as a solid. Regenerable systems, such as the limestone slurry system, although more expensive, produce a solid sorbent, produce a

byproduct, such as sulfuric acid, and have no solid waste.

NOx Emission Controls - The control of NOx emissions from fossil fuel combustion can be achieved through the use of combustion modifications and stack gas treatment. Uncontrolled NOx emissions from coal combustion have been reduced below 200 ppm through burner and furnace modifications in experimental work.⁽⁶⁾ Combustion modifications applied to the Isogo Power Station operated by the Electric Power Development Company of Japan have resulted in emissions averaging 250 ppm on 265 MW furnaces in daily operation.⁽⁷⁾ Emissions at the Isogo facility were reduced from 669 ppm to 576 ppm level through the use of NOx ports, and from 576 ppm to 240 ppm through the use of low-NOx burners.

The greatest potential for minimizing the NOx emissions associated with coal combustion is through the use of ammonia injection. Two basic processes, one of which involves the catalytic enhancement of the NOx elimination, have been developed. Both rely on the basic reactions shown below:



The ammonia is consumed in the process with the nitrogen and hydrogen atoms being converted to water and nitrogen gas when reacted with oxygen and nitric oxide. This reaction will take place without catalytic enhancement if ammonia is injected into the exhaust gas at a temperature of approximately 1750 F. The temperature required for the reaction can be reduced through the addition of hydrogen. The noncatalytic ammonia reduction of nitric oxide has the disadvantages of lower efficiency than catalytic and a narrow temperature window, which implies control difficulties.

The noncatalytic or "thermal" ammonia injection process has been shown to be relatively insensitive to fuel properties in numerous tests, some of which involved coal combustion. The noncatalytic system is shown schematically in Figure 4.

Catalytically enhanced ammonia injection systems offer the advantages of higher NO removal efficiency, lower reaction temperature, and a broad temperature window. The catalytic system, shown schematically in Figure 5, has achieved greater than 90% NO removal in several applications⁽⁷⁾. A pilot catalytic ammonia injection system installed at the Isogo Power Station has achieved 90% NO removal on exhaust gas from coal combustion. Catalyst fouling with combustion particulate, a problem in earlier installations using "dirty" fuels, has not presented problems at Isogo, which uses plate-type as opposed to pelletized

catalysts. The open channels of the plate-type catalyst are less susceptible to particulate matter fouling. Hot-side electrostatic precipitators provide an alternative approach to reducing potential particulate fouling problems, but the experience at Isogo indicates that they may not be required.

A characteristic of both catalytic and noncatalytic ammonia injection systems is the production of some ammonium bisulfite and ammonium bisulfate when high ammonia injection rates are used to maximize NO removal. The experience in Japan indicates, however, that ammonium bisulfite/bisulfate production does not produce significant problems since the deposits tend to form on air preheaters which can be periodically cleaned by water washing or soot blowing.

Emission Standards Achievable - Table 4 summarizes the currently applicable emission standards for coal-fired power plants and the levels of control which have been achieved on various facilities. Note that the current EPA New Source Performance Standards (NSPS) for both coal-fired and oil-fired power plants allow for substantially greater emissions than have been proven to be achievable at certain existing power plants.

NOx emissions of 0.34 lbs/10⁶ BTU have been demonstrated at the Isogo Power Station in Japan without stack gas controls and 0.034 lbs/10⁶ BTU has been achieved with the ammonia injection pilot plant. The level of NOx control reflecting "best available control technology" appears to lie between 0.04 and 0.15 lbs/10⁶ BTU depending on whether catalyst durability on coal proves acceptable from an economic perspective. The 0.15 level appears to be achievable with the use of the noncatalytic process.

SOx emissions of 0.05 lbs/10⁶ BTU represents 95% control over the emissions of coal with a sulfur content of 1%. Most western coals are significantly below this level of sulfur content.

Particulate matter emissions of .005-.01 lbs/10⁶ BTU have already been achieved at two coal-fired facilities which incorporate fabric filtration. Given the increased particulate removal efficiency associated with stack gas scrubbing, it appears as though a standard of 0.005 can be achieved.

For comparison purposes, Table 4 includes emissions data from Alamitos #5, an oil-fired power plant operated by Southern California Edison which is the cleanest oil-fired power plant in California, and Scattergood #1, a natural gas-fired power plant operated by the Los Angeles Department of Water and Power which is the cleanest fossil fuel-fired power plant in the state. Comparing the aggregated NOx SOx and particulate emissions from

Alamitos #5 to the author's proposed best available control technology standards for coal, it is seen that Alamitos #5 could have as much as 50% greater emissions than a modern coal-fired power plant of equivalent output.

Control System Costs - A wide range of cost estimates have been made for the various emission control systems applicable to coal-fired power plants. Shown in Table 5 are the author's estimates for control system costs compared to basic power plant costs based on data from a variety of sources. Scrubbers, non-catalytic ammonia injection and electrostatic precipitators are estimated to account for 27% of the cost associated with producing electricity at the "busbar". Such control costs account for much less than 27% of the consumer cost of electric power since administrative costs and the costs associated with electric power transmission have not been included.

VI. SUMMARY AND CONCLUSIONS

The state of the art in emission control has progressed to the point where coal can be used to produce electricity with less air pollution than is currently associated with electricity produced from the combustion of low sulfur fuel oil. Progress now being made in the development of a new plan for achieving and maintaining the ambient air quality standards in California, indicates that new emission sources can be accommodated provided they do not have emissions which will cause violations. Preliminary air quality modeling indicates that if emissions from coal-fired power plants are controlled to the levels indicated as feasible above, then the localized air quality standard violations can be avoided.

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**Table 1 - Ambient Air Quality Standards Significantly
Affected by Fossil Fuel Combustion**

Pollutant	State Standards	Federal Standards	Precursors
Nitrogen Dioxide (NO ₂)	.25 ppm hrly avg	.05 ppm annual avg	Nitrogen Oxide (NO)
Sulfur Dioxide (SO ₂)	.05 ppm 24 hr avg .5 ppm hrly avg	.14 ppm 24 hr avg .03 ppm annual avg	Sulfur Dioxide
Total Suspended Particulate Matter (TSP)	60 µg/m ³ annual avg 100 µg/m ³ 24 hr avg	75 µg/m ³ annual avg 260 µg/m ³ 24 hr avg	Particulates, sulfur oxides, nitrogen oxides, hydrocarbons
Sulfates	25 µg/m ³ 24 hr avg	None	Sulfur dioxide
Oxidant (O ₃)	.10 ppm hrly avg	.08 ppm hrly avg	Hydrocarbons (HC), Nitrogen oxide
Visibility	10 miles when humidity is less than 70%	None	Particulates, Sulfur dioxides, Nitrogen dioxides, Hydrocarbons

Table 2 - Maximum Pollutant Concentrations, 1977

Basin	Oxidant (one hour - ppm)	TSP (24 hour - µg/m ³)	SO ₂ (24 hour - ppm)	Sulfates (24-hour - µg/m ³)	NO ₂ (one hour - ppm)
1. South Coast	.39*	508*	.132*	64.7*	.69*
2. South Central Coast	.26*	293*	.035	27.5*	.30*
3. San Diego	.25*	240*	.023	37.9*	.36*
4. San Francisco Bay Area	.17*	179*	.090	19.4	.26*
5. San Joaquin Valley	.21*	793*	.092*	73.7*	.18
6. Sacramento Valley	.19*	250*	.014	6.6	.17
7. North Central Coast	.14*	166*	.053	7.6	.12
8. Lake Tahoe	.10*	98	0	-	.09
9. Southeast Desert	.27*	732*	.088 [†]	18.6	.26*
10. Mountain Counties	.10*	72	-	2.2	-
11. Great Basin Valleys	-	-	-	-	-
12. North Coast	-	218*	-	13.1	-
13. Northeast Plateau	-	215*	-	18.6	-
14. Lake County	-	182*	.01 [‡]	3.9	-

* Indicates level in excess of state or federal ambient standard

- Indicates data not available

‡ Total sulfur

† Combination standard - O₃/SO₂ exceeded on another day when SO₂ = .076 & O₃ = .10

Table 3 - Comparison of Emissions from a Coal-Fired, Oil-Fired, and Gas-Fired 450 MW Power Plant Without Stack Gas Controls (Pounds per 10⁶ Btu)

<u>Pollutant</u>	<u>Coal-Fired^a</u>	<u>Oil-Fired^b</u>	<u>Gas-Fired</u>
NOx	0.45	0.17	0.11
SOx	1.33	0.52	nil
PM	4.20	0.04	nil

Notes: ^a Based on burning 1% sulfur coal

^b Based on burning 0.5% sulfur oil

Table 4 - Controlled Power Plant Emissions Comparison

	<u>Emissions, lbs/10⁶ Btu heat input</u>		
	<u>NOx</u>	<u>SOx</u>	<u>PM</u>
EPA NSPS, (oil)	0.3	0.8	.1
EPA NSPS, (coal)	0.7	1.2	.1
ISOGO Power Station (coal)	0.34	0.02-0.1	.035
ISOGO NH ₃ Injection Pilot Plant	0.034	-	.035
Colorado Ute Nucla Plant (coal)	-	-	.01
Pennsylvania Power and Light Sanbury Plant (coal)	-	-	.005
Author's Proposed BACT (coal)	0.04-.15	0.05	0.005
Alamitos #5 (0.25% oil)	0.17	0.26	0.049
Scattergood #3 (gas)	0.034	0.0008	0.0025

Table 5 - Estimated Costs Associated with Electricity from Coal

	<u>Capital Cost \$/KW</u>	<u>Electricity Cost Mills/KWHR</u>	<u>Percent of Total Electricity Cost</u>
Basic Power Plant	600	11	42
Scrubbers	110	3	11.5
Electrostatic Precipitators	35	1	4
Non-Catalytic Ammonia Injection	12	3	11.5
Fuel Costs	Externalized	8	31
TOTAL	757	26	100

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Figure 1 California air basins

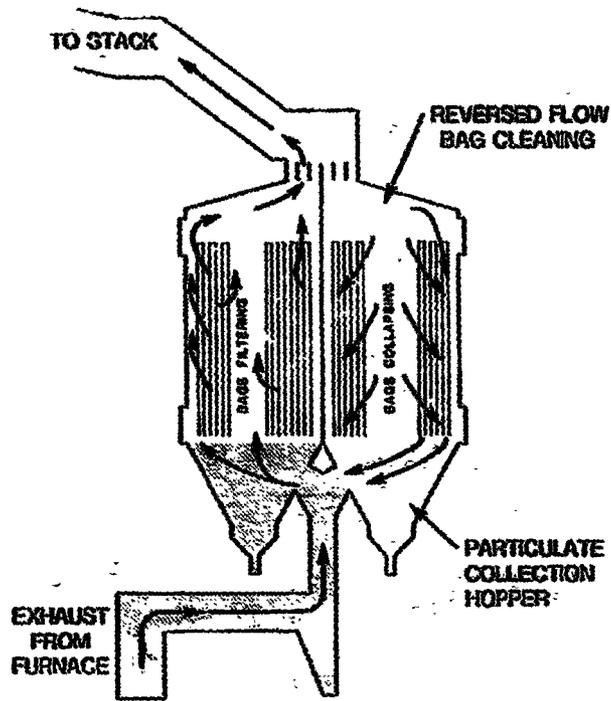


Figure 2. Fabric filtration (baghouse) system

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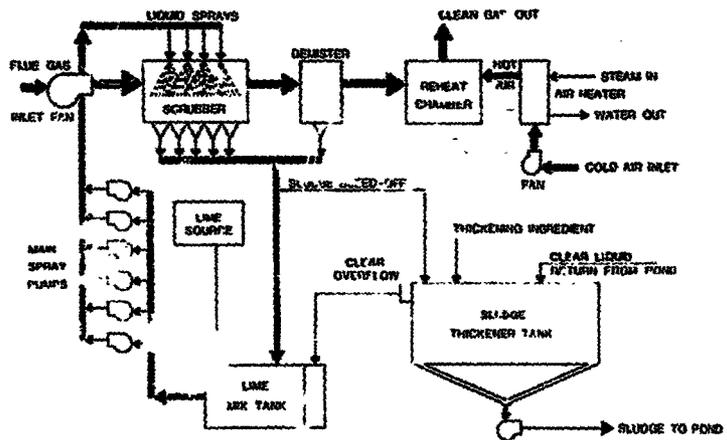


Figure 3. Limestone slurry flue gas desulfurization

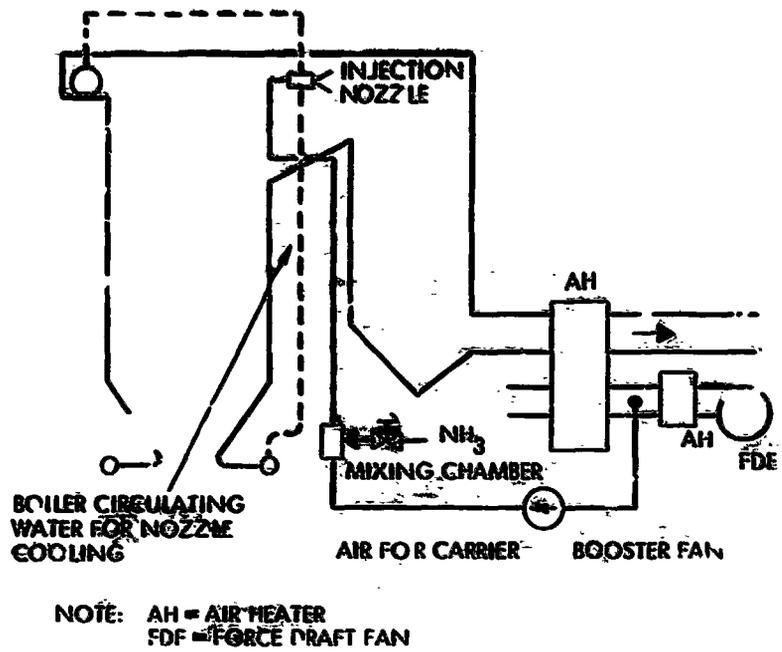


Figure 4. Noncatalytic ammonia injection system

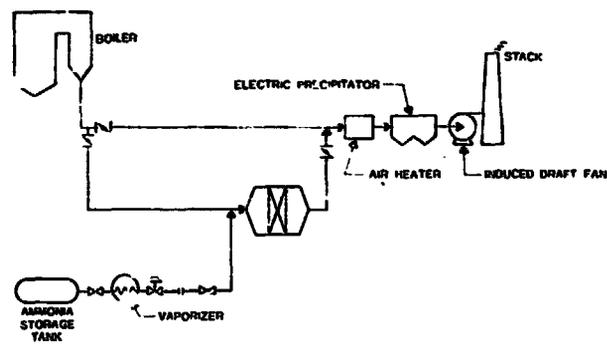


Figure 5. Catalytic Ammonia Injection System

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WATER AS A CONSTRAINT TO THE
USE OF COAL FOR CALIFORNIA

Ronald B. Robie, Director
Department of Water Resources

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The Resources Agency
State of California

I would like to begin by stating that I appear before you today in dual capacities: first as Director of the Department which plans for the management of California's water supplies, and secondly, as sponsor of a coal-fired power plant to furnish necessary power for the State Water Project. As part of our power plant development, we also will have to solve some problems and meet the regulatory requirements which I will address today.

The State Water Project delivers large quantities of water from Northern California to the San Joaquin Valley and Southern California.

As water must be pumped from the Sacramento-San Joaquin Delta to the places of use, the Project is a large user of electric power. Under normal water conditions, the Project will require about 5.5 billion kilowatt-hours this year (about one-third that sold last year by the City of Los Angeles) and over 10 billion kilowatt-hours by the year 2000.

Presently, power for the Project is obtained from power recovery plants on the California Aqueduct, by purchases from major California electric utilities, and by purchases from utilities in the Pacific Northwest. While some power purchase contracts will be renegotiated, others will expire in 1983. We are evaluating several possible sources of energy for future project operation to replace that lost by contract expiration. These sources include hydroelectric, geothermal, coal, nuclear, and others. The Department has participated in research and development activities related to wind energy and has also submitted a proposed solar-electric research project to the Federal Government.

We have proposed development of a 1000-MW coal-fired power plant as one of the most practical ways to fill a portion of our future power need.

This Department will be the lead agency and manage the development through all stages. The Department would generate only for our own needs and would retain ownership of about 350 MW of the total plant capacity. The remaining capacity would be owned by public and private utility participants. It is presently envisioned that the

plant would be comprised of three generating units, each being completed one year apart, the first being on line in 1987.

One of the most important considerations in use of coal, or for that matter, any fuel used in a thermal plant, is the water supply for cooling. I cannot overemphasize; this is not exclusively a coal plant problem. Competition among various water uses is keen and, of course, during the drought conditions of the last two years this competition was especially intense. In the past, most thermal plants were constructed near the coast or on connected bays where ample supplies of saline water were available for cooling. Today, however, for many reasons thermal plant sites are moving into inland areas where water is less abundant.

A 1000-MW coal-fired plant would require on the order of 15,000 acre-feet per year of fresh water. As the following tabulation indicates, cooling is by far the largest requirement:

<u>Purpose</u>	<u>Requirement (Acre-foot/year)</u>
Cooling	13,300
Domestic	10
Boiler makeup	300
Flue gas scrubbing	1,200
Miscellaneous	200

When we use water of high salinity, however, buildup of salt concentration by evaporation limits the reuse of water in the cooling system and water requirements could increase to 30,000 acre-feet per year for a 1000-MW plant. The Department, in cooperation with major electric utilities has recently completed pilot plant studies which indicate that with proper pretreatment, brackish agricultural waste water can be used for power plant cooling, where the TDS concentration of the coolant is increased to as high as 70,000 milligrams per litre by recirculation. We will soon have a full report on these studies.

This Department and the California State Water Resources Control Board have made studies to determine the quantities of water needed for future power plant cooling and to develop a consistent policy regarding cooling water uses.

The principal guidance to the Board and the Department is Article X of the California Constitution, which controls the waste of water and requires use of water to be both reasonable and beneficial. Both the Board and the Department are required under Section 275 of the Water Code to implement this provision. The Department's policy is that California's water resources shall be managed in a manner that will result in the greatest long-term benefit to the people and that water shall be reused to the maximum extent feasible. Consistent with this policy, the preferred sources of cooling water at inland sites are urban and agricultural waste waters and other poor-quality water. The Water Resources Control Board's policy regarding water for power plant cooling provides that cooling water should come from the following sources in order of priority depending on environmental, technical, and economic feasibility considerations: (1) wastewater being discharged to the ocean, (2) ocean waters, (3) brackish water from natural sources or irrigation return flow, (4) inland wastewaters of low TDS, and (5) other inland waters. Where the Board has water rights jurisdiction, use of fresh inland waters for power plant cooling will be approved by the Board only when it is demonstrated that the use of other water supply sources or other methods of cooling would be environmentally undesirable or economically unsound. In issuing a permit or license for water for power plant cooling, the Board considers the reasonableness of the proposed water use when compared with other present and future needs for the water sources. The State Department of Food and Agriculture also opposes the use of fresh water for power plant cooling where that water could be used elsewhere.

In all of these determinations regarding power plant cooling, no rule applicable to all circumstances is possible. Reasonableness of use depends on all aspects of each particular situation; therefore, each plant must be examined on a case-by-case basis.

The State Board implements its policy by intervening in Energy Commission proceedings.

The Legislature also has established policy on power plant cooling. The Waste Water Reuse Law of 1974 directed the Department to investigate the use of reclaimed waste water for beneficial purposes, including power plant cooling. This law also declares that water conservation requires the maximum practical reuse of waste water. The results of these DWR studies pertaining to power plant cooling are presented in DWR Bulletin 204, "Water for Power Plant Cooling", July 1977. Another recent law relating to water use for power plant cooling permits The Metropolitan Water District of Southern California to provide up to 100,000 acre-feet of Colorado River water and up to 60,000 acre-feet of State Water Project water per year for cooling purposes. This same law, however, also directs that agricultural waste water and other water not suitable for other purposes shall be used for cooling to the extent practicable.

Let's consider some forecasts published recently in Bulletin 204. Projects by the Department and the California Energy Commission vary widely depending on the assumptions made. On the average, however, they indicate that in 1995

about 280,000 acre-feet of power plant cooling water per year will be required at inland sites assuming evaporative cooling. Agricultural waste water available for cooling at that time in the southern San Joaquin Valley would be slightly in excess of 140,000 acre-feet per year. In the Palo Verde Valley, agricultural waste waters are returned to the Colorado River to satisfy downstream water rights, and use of these waters for cooling would be contingent on increased compensatory releases at Parker Dam. The utility must pay to make this water available. In the Imperial Valley, Colorado River water is also used for irrigation, and the drainage is routed to the Salton Sea. The volume of drainage water is more than ample to meet projected cooling needs; however, a new water level balance in the Salton Sea would result. This change, and especially the effect on the fishery, has not been evaluated.

Recently, studies were concluded at UCLA regarding utilization of coal for power in California. These studies were jointly funded by the Department and the California Energy Commission. The general criteria for power plant siting considered in the UCLA studies (air quality, population, etc.) pointed to desert region locations. Limited water supply studies were done for several selected potential sites. Here, water supply alternatives considered were the Colorado River, agricultural waste water, and ground water of varying quality. In general, it was found that there would be sufficient ground water for potential power plants at the Cadiz, Goffs, Barstow, Rice, and Blythe sites, and sufficient agricultural return flows at all except the Blythe site. Constraints on the use of each water source would require specific studies for each alternative site to determine the costs and engineering and environmental factors in getting the required quantities of water to the plant. Studies would also be required to determine the existing water quality at each source to determine its fitness for other purposes and the amount of makeup water required to keep salt concentrations from rising too high.

In some areas, use of ground water for cooling would result in mining (extraction at a greater rate than natural recharge). Studies are required to determine the ground water reserves needed for the life of the power plant. For our new power plant, the Department will conduct more extensive studies on water sources as part of our site selection process. The Department will soon publish a bulletin on ground water data for the southeastern part of the State. This will utilize recently developed USGS data.

One of the questions that always comes to mind when discussing cooling water requirements is: Can anything be done to reduce the amount of water needed? This Department is continuing to study this question. Of course, within the plant system the basic concept of reuse of water will be carried out to the fullest extent possible, e.g., highly saline water from the plant cooling system will be used in ash handling, dust control, or other purposes where quality is not a problem. Dry cooling was reviewed and found to have drawbacks. This system is comparable to the radiator in your car--air cools the water in a closed system and no water is lost. Besides having higher

capital cost, dry cooling towers are not as effective in reducing water temperature as evaporative systems. Turbine outlet steam temperatures are, therefore, higher and turbine efficiencies are lower. Fuel consumption rises, and since dry-cooled units depend on cool ambient air temperatures to carry away heat, in hotter climates, efficiencies drop further.

The Department is participating in a prototype test of a wet-dry cooling tower. This study is being sponsored by Southern California Edison Company; several other utilities and governmental agencies are involved. Such a tower would first use a dry system to partly cool the water; the water would then drop into a conventional evaporative section. Louvers would control the amount of air passing through each section. Under cooler ambient conditions, most of the cooling would be accom-

plished in the dry section and water savings should be up to 25 percent, or hopefully more.

I have not mentioned coal slurry pipelines and the water supply impacts of interstate transfers of water. Most of the Western states zealously guard their water resources and this can be a serious impediment to use of this form of coal transport. Whether Congress will enact coal slurry legislation is open to question, and if it does, "area of origin" provisions for water will surely be a part of the considerations.

In summary, there is sufficient water available in California for power plant cooling. The resource, however, is finite and every effort must be made in this use, as in all others, to obtain maximum conservation and recycling of the resource.

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P. III

Session III: ENVIRONMENTAL ASPECTS OF COAL USE FOR CALIFORNIA

Session Cochairmen: Richard Sextro (LBL, Sierra Club)
Richard Green (JPL)
Panel Members: Dwight L. Carey (Sierra Club)
Thomas Austin (ARB)
Ronald Robie (DWR)

OPEN DISCUSSION BY ATTENDEES

UNIDENTIFIED ATTENDEE:

I would like to discuss a little bit further the point that Dwight Carey raised concerning the adequate control of disposable solid and liquid waste. He says in his brief that is contained in the bulletin, "Of greatest concern is adequate control of generated air pollutants and disposal of solid and liquid waste, since acceptable technologies or handling techniques have yet to be conclusively demonstrated." Basically, I think there are two points that I would like to raise with regard to this that might bear a little further discussion. Specifically, we have the problem that has been referred to, or at least been researched by, the University of California at Davis, concerning the small particles that are released in the fly ash. These are the submicron particles that are taken into the lungs. Tests have shown that there may be the possibility that this type of respiration could induce cancer. Also, there is the problem of the disposal of the sludge or the bottom ash that is captured in the processes at the plant. I'm a little concerned about the final disposal of this waste. Coal does contain small quantities of uranium and thorium. It is radioactive to some extent, so there is the solid waste disposal problem which also must be dealt with. I think that with respect to the entire fuel cycle, the small particulate problem may also exist. During

the transportation and storage in the handling of coal there may also be the small particle problem. I raise this at this point merely to raise the consciousness level of this conference to these problem areas because I think that in dealing with coal in California we are going to have to hit these head on. With this long prologue, I'll ask the question of the entire panel. Basically, what type of research programs do you think the State of California or the Nation, for that matter, should be embarking on in order to get answers to these questions so that we will really know whether or not we do have a viable coal option here in California.

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DWIGHT CAREY:

I don't have the answer to that question. I think that you have expressed it very distinctly right there. I don't think we do have a good answer to the specifically solid and liquid waste disposal problem. In some earlier discussions that we have had on coal utilization projects in California, those have been two particular issues where someone has said, "OK, now we think we have got an issue, but no one has been able to come up with an answer." As far as what type of research projects are needed, I'm afraid right now I don't have an answer to that question either.

THOMAS AUSTIN:

I would like to comment on that question. One of the things that personally concerns me is that a lot of the comparisons that have been made in the literature regarding the particulate or radioactive pollutant emissions from coal fired power plants compared to other sources of electric power generation, be they oil fired power plants or nuclear reactors, are really based on the use of the kind of particulate control technology as required to achieve the current Federal standards. Most of the comparisons that I've seen do not consider the particulate and radioactive pollutant concentrations that result from the combustion of coal when the plant is equipped both with precipitators or a bag house and wet scrubbing. It is

clear that a lot of that particulate, sub micron particulate and the radioactive particulate are removed by the devices which are now used in Japan. When you look at how the particulates, the metals, the radioactive pollutants from Japanese-type power plants compare with US power plants there is a gross difference. The particulate problem, I believe, is therefore somewhat overstated, although clearly there should be further study of the potential long range impacts.

RICHARD SEXTRO:

Just by way of noting, I recommend to you Session VI, which is I guess tomorrow afternoon. It deals with some of the control technologies and certainly that would be an appropriate place to bring that question up again.

DON TEIXEIRA:

I am from EPRI. Let me just say that with regard to the fine particle problem, it would appear that, at least partially based on some of the research that has been conducted at EPRI, there are some answers in the offing and perhaps we can even get into those tomorrow even though that isn't my scheduled subject. Getting back to the subject at hand, I have one comment to make on the question for Mr. Austin. I think that it is important to note that with regard to the NO_x emissions that you mentioned on the ISOCO plant you're quite accurate and I would certainly concur with the data shown on your graph, except I think it is important to note that the scale of the research to date is very small. It is at about a maximum of 1 megawatt research and there is a considerable amount of scale cut yet that remains to be performed before one can say it is commercially available. Not to say that it couldn't be, but at this point, it is not.

Secondly, the question that I had was with regard to ammonia control technologies, be they catalytic or noncatalytic. I would like to get some feedback from the ARB on how you feel about ammonia

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emissions, their impact on the environment, and what the tradeoffs might be between controlling NO_x and the subsequent ammonia emissions.

THOMAS AUSTIN:

OK, first of all, regarding the potential problems associated with scaling up. In Japan, ammonia injection has been used on very large units, as large as would be used in coal fired power plants. It has not however been applied on a large coal fired unit. You are correct in stating that approximately 1 megawatt is the size of the existing coal fired pilot plant; however, a two to three hundred to one scale up is not so outrageous as it might appear. That kind of scale up has been done successfully in the past. I think something else that needs to be pointed out, when you look at the composition of the gas that would be treated by catalytic ammonia injection systems, it is possible to put a precipitator up stream in the system so that the gas that the ammonia injection system would treat on a coal fired power plant would be very similar to the gas that it has already successfully treated in installations with basically cleaner fuels. As far as ARB is concerned over the potential ammonia emissions, from what we've seen in Japan it is possible to control the ammonia injection rate to match it to the NO_x emission rate so that the ammonia emissions are kept below 10 parts per million. We are unaware of any reason for us to be particularly concerned about that low rate of ammonia emissions. I think it would be appropriate though for regulations applied to major facilities, like the power plants, to require continuous monitoring of the ammonia emissions to make sure that under any upset conditions, the ammonia injection system would be automatically shut down to prevent the release of substantially higher concentrations of that pollutant.

RALPH SPAULDING:

I am from Kaiser Engineers. I would like to pursue with Mr. Carey his concern for the sociological impacts on coal mining areas. More particularly, which group of people should have the most say so in what those sociological impacts will be, the residents of the area or the residents of the consuming area?

DWIGHT CAREY:

I guess it depends on whether you are a resident of the consuming area or a resident of the producing area. I have been in both places and I don't think we can speak for those people any more than they can speak for us. Part of the problem is trying to balance the regional concerns; that is, recognizing that just because Utah can say, "California go somewhere else for your coal because it is ours," or New Mexico, Arizona or any other state can disassociate themselves from the State of California, can California say, "That is ours, we want it." It's a very regional system and it's going to take a tremendous amount of regional cooperation to achieve the balance. That is to say, they have as much right to determine their future as do we, and it is not going to be the choice of either party, but a balancing of some sort in the way of concerns. Until you actually get into the process, I don't think you can determine where that balance is going to end up.

RALPH SPAULDING:

I couldn't agree with you more. However, your organization in many respects has, in the State of Utah, taken the opposing position, contrary to the local residents; the residents tend to prefer coal development. The Sierra Club, speaking on their behalf, has said that it is a terrible thing for these rural counties. More specifically, we have had a lot of statistics thrown around here today. I was reading a report prepared by Five Counties Association of Governments last week on the sociological impacts in Garfield County, which is a rural county in Southern Utah. Part of that study polled the residents and I believe it was 97% that felt that coal development was good for the county and for the element, particularly in Brice Valley, which is one of the more environmentally preferred regions.

DWIGHT CAREY:

Only in answer to that I would say two things. There often is a lack of realistic perception on the part of the people being polled as to what they are actually answering to. (Laughter)

Obviously my answer has been interpreted by two different groups of people in two different ways. Their answer depends largely upon how the impacts are explained and the fact that on top of that, there are national priorities and national interests that in turn go on top of the fact that we are looking at two interested utilization regions.

BILL SAMUEL:

I'm from Fluor but the opinion or comment I'm about to make is mine and not the company's. I come from the eastern part of the country, West Virginia and Western Pennsylvania where we have burned vast quantities of coal, soft coal, for generations. I'm not aware of any greater incidence of lung cancer or other types of diseases which could come from the long range emissions that you would get from coal. I'm wondering to what extent we are raising "Boogie Men" here when we are talking about weird effects we might expect from stray trace elements etc., because they certainly aren't apparent out there. One last comment, I just can't help but hope we never make the mistake of throwing out our free country baby with the conservation bathwater.

RICHARD SEXTRO:

This is a comment not a question. I feel that that question deserves some answer, in that for somebody that has looked at some assessments, which is the game that I'm in at Lawrence Berkeley Laboratory where certainly are a lot of epidemiological data on the question and the correlation between emissions and health effects. I don't think there is any question that those exist; you can argue at what levels they exist, but there is no question they exist.

I have a question for Mr. Robie, concerning DWR's proposal for a coal plant. You mentioned it was 100 megawatt facility and I wanted to know if you plan on building that all at once, or do you plan on doing it in incremental stages? The second part of the question; have you determined a coal source for that facility?

RON ROBIE:

In response to your first question, my staff keeps criticizing me because we are really talking about three 330 megawatt units and they say that doesn't really add up to 1000, but it is close enough for the Director of the Department. Actually we are targeting our studies for specific site location based upon incremental construction of three megawatt units. Assumptions being made now, with all of the studies coming out favorable, they would all be built at one site. With regard to the source of coal, as was mentioned earlier, Prof. Anderson's report of UCLA was made initially, at our request, as part of our studies of a couple years ago in the development of a coal plant. We are going to start again, or continue from where they left off, in terms of sites and conduct more detailed site selection studies which will be done concurrently with studies of specific coal sources, which they also examined. We'll have to put the two together in the orderly process of selecting sites and coal sources--they just go together. The source of coal depends in part on where you build your plant, so we are going to make two concurrent studies directed by the Department, beginning in the next few months.

LARRY CHASET:

I'm with the California Energy Commission. I have a couple of questions of Mr. Austin. This is more in the nature of a hypothetical question. Assuming that we are proposing or that the utility proposed to build a power plant in a nonattainment area for oxidant and under the ARB's interpretation of the new source review rules, NO_x tradeoffs would be required. A couple of things can happen, first of all, the plant would have to be built with best available control technology to control NO_x. First question is how would, at any point in time, the best available control technology be determined? And again, if the NO_x tradeoffs were required for the oxidant violation and the applicant proposed to come in under an innovative technology exemption, how would an innovative technology be distinguished from best available control technology, and to what extent can the so-called "moving target" problem be mitigated?

THOMAS AUSTIN:

As far as NO_x tradeoffs are concerned, you're correct in indicating that ARB has required NO_x tradeoffs. However, not all areas of the State are going to require NO_x tradeoffs just because they are nonattainment for oxidant. Surely NO_x tradeoffs will be required throughout the central valley and in the very large air basins such as the South Coast air basin, but the atmospheric chemistry taking place is substantially different in areas like the southeast desert portion of Riverside and San Bernardino County. Imperial County and other areas of the State, depending on where the site is, may not be necessary to talk about NO_x tradeoffs. NO_x may only have to be controlled to the extent necessary to minimize the emissions impact of the facilities through the application of BACT or to the extent necessary to prevent violations of the NO₂ standard which is not much of a problem in some of the more rural areas. As far as what will constitute BACT, that will depend on when an application for permit to construct facility is filed with an Air Pollution Control District. If a permit to construct a facility was filed now, ARB would have to expedite its current efforts to develop BACT regulations for coal-fired power plants. I think that at this time BACT would end up being something in the neighborhood of 100 ppm, as far as NO_x is concerned, which may be achievable without the use of a catalytic ammonia injection system. Whether or not something lower than that will end up being required is going to depend on when we actually see an application and what has happened in the interim as far as the development and demonstration of more sophisticated technologies, both in California and elsewhere.

LARRY CHASET:

What about the distinction between BACT and so called innovative controls which might be used as a exemption from the tradeoff requirement?

THOMAS AUSTIN:

Again that is going to depend on exactly when an application is filed. At this point, I think it might be appropriate to consider the

application of a catalytic ammoniac injection system to a coal fired power plant as innovative control technology and that may make it somewhat easier for the first applicant in California to obtain a permit on an expeditious schedule. However, I think that there is enough progress being made right now and the use of advanced technologies in Japan is such that, in the very near future, there is going to be something far more extraordinary than the use of ammonia injection on a coal fired power plant required before any exemption is granted for the innovative control technology aspects of the proposal.

LARRY CHASET:

One final question. If as a condition of being issued a permit or as a condition of having its authority for construction granted by the Energy Commission, the utility is required to install an advanced NO_x control technology and it turns out later on that the technology doesn't work as well as it was supposed to, what happens then?

THOMAS AUSTIN:

That depends on the specific technology we are talking about. It's possible in cases where innovative technology is being demonstrated that the risk, normally associated with having to comply completely with the applicable regulations, can be reduced for that particular source within some reasonable range. For example, if someone is attempting to achieve a 95% reduction in NO_x through the application of a catalytic ammonia injection technology, and he only achieves 92%, I think that in a case like that the source should not be subject to being shut down or having to substantially modify the facility in order to remain in operation.

One thing I want to point out is that innovative technology exemption exists within the new source review rules. That exemption is only available when the Air Resources Board and the Environmental Protection Agency determine substantial environmental or public welfare benefits to California. Just because someone comes up with an innovative technology that would allow many very large facilities to be constructed in the State which could potentially, in some locations, exacerbate the problem, doesn't mean that there is

going to be an exemption granted.

IKE EASTVOLD:

I represent the Sierra Club of the desert region. For Mr. Robie, you spoke of water balance in regard to the agricultural drain water return flows to the Salton Sea. I wonder if you could give us some statistics on what the return flows are today and how many acre-feet of water that you see as available for power plant cooling without adversely affecting the wildlife resources of the Salton Sea.

RON ROBIE:

No, I really can't, the point is that if you reduce the amount of drainage water going to the Salton Sea, which is better quality water than the Sea itself, you will increase the salinity of the Sea. The Department of Fish and Game, when I first went to work for the Assembly Water Committee 18 years ago, said that Corbina were about ready to expire because of rapidly increasing salinity. They are still there and strong. I think that you will have to have studies as to what we really can find out. What we currently think is that there is uncertainty about the capability of fishery resource in the Sea to survive. I don't think you could embark on a program using that wastewater until you have a better handle on it. So, I couldn't tell you what the amounts would be.

IKE EASTVOLD:

Then on what do you base your statement that there are ample drain water return flows to the Salton Sea for power plant cooling?

RON ROBIE:

My statement was that there is an ample quantity available, but it would cause an impact on the Sea, which has to be evaluated, and therefore wasn't recommending it be used. I was merely explaining what the current status is.

IKE EASTVOLD:

Are any studies in preparation, to your knowledge, that would give us that data?

RON ROBIE:

Particularly with regard to the Department's program, if we examine in greater detail, sites that could use the Salton Sea drainage water which would be coming from the new Alamo Rivers, we would make those studies, yes. We haven't started them yet. I don't know of any others being made by people who are interested in the subject generally. There may be some but I am not aware of any, and as I say, this is the present status of things in terms of quantity.

IKE EASTVOLD:

To move to ground water in the southeast desert then, perhaps you could give us an idea of some of the impacts we would be looking at if we were to extract groundwater in the amounts necessary for a power plant cooling at some of the sites that have been identified in the Anderson Report. What kinds of impacts would you anticipate from such extraction in regards to existing surface waters, that is springs and underground flows and washes, and in regards to possible changes in the biological regime of the desert?

RON ROBIE:

Again, I can't give you a specific answer to that kind of general question. You would have to examine each area specifically. It depends on the depth of the aquifer, I am certainly not a geologist, but if you are taking water from 1000 feet or more down, I don't know whether you would have any surface effect. I don't think you would. I think that each area would have to be examined in terms of possible subsidence, reduction in spring flow, in the area

and all of these factors. I'm certain there are areas where you could mine groundwater and take substantial quantities out without adverse impact. The only principal impact would be in subsequent years, if you wanted the water, it wouldn't be there. These are areas where you anticipate no major development, and I think that the mining of groundwater may be a desirable thing to do in terms of industrial uses of various kinds, other than power plant cooling. This is just a feeling on my part.

IKE EASTVOLD:

A forthcoming DWR bulletin in the 204 series you mentioned is on extraction of groundwater. Does that bulletin look at some of these sites identified in the Anderson Report, in reference to impacts of extraction of ground water?

RON ROBIE:

This is a basic data bulletin, I hope I didn't overstate it. No, it's not specific in the sense you might be looking for, but it is a basic data bulletin gathered by the United States Geological Survey. We are publishing it, to be a useful tool for evaluation of a specific site.

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IKE EASTVOLD:

To your knowledge, are there any baseline data available for the specific sites identified in the report?

RON ROBIE:

There are some. We have done some work. There are some wells that have been monitored and some data that our southern district of the Department of Water Resources has. I frankly can't tell you the level of it, but I would be happy to provide you that information if you contact me afterwards.

IKE EASTVOLD:

But there is no data on the impacts on the surface flows or the surface biological regime of extraction of groundwater from those sites?

RON ROBIE:

I'm not aware of any, but I don't want to say that you should imply that there are going to be tremendous impacts if and when we do have the information.

IKE EASTVOLD:

No, I'm not implying that, I'm just asking--

RON ROBIE:

I know that you are not, but all over the State there are substantial quantities of ground water being taken out and there are very specific impacts that you can measure. I don't think that there are very many surface streams in the general area to be affected, and I think that with my impression and my general knowledge of the subject that there would be minimal impacts, but we would have to have studies to decide whether this is in fact true.

IKE EASTVOLD:

I would like Mr. Austin and Mr. Carey to comment on the area of socio-economic impacts, particularly the area of impacts from increase in recreational use as regards the influx of construction workers into small desert areas. Mr. Austin, in regard to disturbance of desert soils from increased recreational use, particularly off-road vehicle activity, and direct impacts from construction, transmission lines, access roads and the plant site itself; what problems do you anticipate with increasing the already high level of background particulates in the desert? Mr. Carey, what impacts of desert resources do you anticipate from increased recreational use?

THOMAS AUSTIN:

Let me comment very briefly. First, I'm not sure I fully understand the question. If you are asking about the particulate impacts associated with the activity that is necessarily related to the construction and operation of a power plant, that is something that the Air Resources Board has started looking at. Our preliminary

look into that area indicates that the impacts would not be significant at all. However, in your question you kept talking about recreational vehicles and I don't understand how that is related to the discussion of possibly building a coal facility at some location in the state. Clearly there are a lot of particulate impacts associated with RV parks and things of that nature, but what does that have to do with a coal-fired power plant?

IKE EASTVOLD:

In the desert, we have very shallow soils which are kept in place by crusts sometimes referred to as desert pavement crusts. Once those crusts are broken, particulates that are kept in place underneath become airborne until an equilibrium is reestablished. This process goes on whenever any desert soil is disturbed, particularly the desert pavement surfaces.

DWIGHT CAREY:

If I can interrupt here I think that the indirect connection that Ike is trying to point out is the fact that by planning or by constructing a large facility in a sparsely populated area, you increase the population, therefore you increase the use of the desert environment, thereby hypothesizing that you are going to increase the recreational activity.

THOMAS AUSTIN:

The magnitude of those impacts could be dramatically different depending on the location that was chosen and, in particular, whether we are talking about a mine-mouth operation or whether we are talking about a coal plant being fed coal by some transportation network. If the transportation network is involved, the impact, I believe, would be fairly minimal as far as the impacts associated with the construction and the disturbance of the soil during that phase. There are techniques available to hold down the particulates and to restore crust and I think it would be possible to see that those were utilized during the construction. Since we are not talking about a mine-mouth operation in California, I wouldn't

think that the impacts would be as great as they have been in other western states.

DWIGHT CAREY:

I'm, in a sense, agreeing with Ike that, yes, you can have increased recreational use of the desert from increased population density, but to address the specifics, I would have a great deal of difficulty with what that is going to mean to the resources, except increased impact.

WAYNE HOFFMAN:

I'm with the Natural Resources Defense Council. This question is directed to Tom Austin of ARB. You implied that you expect under present technology that coal fired power plants could be permitted in areas where the standards would be met, particularly referring to particulate matter SO_2 and NO_x . You seem to base this assumption on the ISOCO plant and some of the other data that you provided, which was all related to the EPA standard, a standard based on pounds per 10^6 BTU. The Clean Air Act Prevention of Significant Deterioration Standards, that is, the maximum allowable increase standard for attainment areas, are standards which are measured differently, I believe micrograms per cubic meter. Isn't there some error in the assumption that the control of this number of pounds that you indicated would meet the standard? Isn't there an error in that assumption when you have to consider the ultimate concentration which would take place from a power plant. Therefore, it seems to me that the outright assumption that a plant meeting these standards would meet the Clean Air Act standards may not be a legitimate conclusion. Would you discuss briefly the relationship between those two standards and how large a plant one might expect could be permitted in an attainment area.

TOM AUSTIN:

I didn't go into the prevention of significant deterioration requirements because that's a program that has several tiers to it. It is something that we have looked into. It is something that

the Energy Commission has also looked into. The modeling results that have been completed to date indicate that a power plant equipped with the kind of controls that I was talking about could be operated in compliance with the prevention of significant deterioration increments for class 2 and class 3 areas. The Energy Commission has been doing a lot of work in that area, and basically, you just have to make sure that you don't locate the power plant somewhere that the plume is likely to have a ground level impact a very short distance from the facility. You have to make sure that you don't locate it upwind from a cliff or a rise. If you put it in a fairly flat area, the concentrations are low enough from a well controlled coal plant that you won't have significant impacts. Obviously, it would be imprudent to talk about locating coal-fired power plants upwind of class 1 areas, of which there will be several in the State. However, when we look at the sites that have been discussed by DWR, the Energy Commission and UCLA, most of those sites are not upwind of class 1 areas. Some of the sites that are upwind of the class 1 areas could also avoid problems with violating the increments by applying controls to other facilities which are in the path of the plume as it would go to the class 1 area. In attainment areas it may be possible to totally mitigate the effects of a new coal-fired power plant by applying some controls to existing power plants. In Imperial County, for example, relatively small oil fired steam generators that are operated by the Imperial Irrigation District, are substantially higher in emissions than a very large coal fired facility equipped with the kind of controls that are feasible today.

WAYNE HOFFMAN:

Just one brief question, it is still true, is it not, that tradeoffs between basins are not permitted?

THOMAS AUSTIN:

No, that is not true. The State of California can receive a delegation from the Environmental Protection Agency from most of the programs that are mandated by the Clean Air Act requirement and, as far as the ARB is concerned, as long as it can be demonstrated

that there will be a new air quality benefit associated with the project, interbasin tradeoffs are acceptable. This is going to be easiest in cases such as a project on the edge of one basin with the tradeoffs on the edge of the other basin. There can be some significant separation between the tradeoffs and the emission source depending on the topography of the area, the meteorology of the area and the type of source you are talking about.

LARRY MARGLER:

I am from the Environmental Science Engineering Program at UCLA. My comment and question are directed mainly at Mr. Sextro. You mentioned that the greatest environmental impact resulting from coal utilization in California would be deaths and injuries from grade crossings accidents. Science Applications, Inc. has recently submitted a report to the Federal Office of Technology Assessment, in which they did a grade-crossing analysis for 4 different scenarios. In particular, there was one from a six million ton per year movement between Price, Utah and Barstow, California. It was looked at with two different transportation modes: one unit train, one slurry pipeline. They estimated that under present conditions, there would be about one death at a grade crossing along the route every three years. It was concluded in the report that the grade crossing accidents would be very route-specific, and also they generally would be lower than is often assumed. In fact, that is often stated by the pipeline proponents. Do you have any comment on that and also I'd like to hear about your study and methods.

RICHARD SEXTRO:

The detailed study in method perhaps you and I can discuss after the session. Let me just say that feeling the constraint of time, I didn't issue all of the qualifications to these data that perhaps I should have. These were data compiled on a national basis in the so-called MERES data base which was put up by EPA. We looked at the data to some degree and found that much of the data relied on were eastern railroads, eastern grade crossing accidents. In fact,

if you look at it per ton mile per grade crossing, that's where most of the incidents have happened. There hasn't been, up until very recently, any significant hauling of coal in the West by rail. What one sees in the East is probably a relatively higher abundance of unprotected grade crossings of blind corners and things like that, that perhaps do not predominate as much in the West. You are correct in pointing out that it is very route specific. We use the data and in our report we qualify our findings to be based on a nationwide data base and not on the perhaps better data that one might obtain from the West.

CHARLES MANN:

I am from Energy and Environmental Analysis Inc., in Arlington, Virginia. I have a question to address principally to Mr. Austin. If an industrial firm is considering siting a new boiler in a nonattainment area and, given that they would have less flexibility in siting than a utility, is the best available control technology for a new industrial boiler a coal fired boiler with all the control equipment you can put on it, say an FGD scrubber and a bag house; is it an oil fired boiler with the same equipment; is it a gas fired boiler, or is it a choice between fuels to be considered in the definition of best available control technology for siting a new unit in a nonattainment area?

THOMAS AUSTIN:

Yes, we think it is appropriate to consider the fuel when determining what best available control technology should be for a particular source. That is because some users of boilers are going to be under great pressure to use certain fuels. As long as those fuels can be burned in a relatively clean manner, I think it makes sense to have the emissions regulations reflect what can be done with that particular fuel. This is an approach which is acceptable now, when it may not have been acceptable in the past; it is acceptable now because we have a new source review rule which essentially requires that, regardless of the individual controls applied to a facility, the total facility itself must meet certain requirements as far as not having an impact

on the downwind areas. As long as that new source review regulation applies to the project there is no major problem associated with having a separate standard apply to a piece of equipment, depending on the fuel it is using.

CHARLES MANN:

Let me rephrase my question because I think you missed my point. Would an application to build a new coal fired boiler that had the best control equipment on it be rejected on the grounds that the emissions from an oil fired boiler, that would obviously fill the same steam need, would have lower emissions.

THOMAS AUSTIN:

No, the Air Resources Board is essentially taking the position that we have to face up to some of the realities that are upon us now because of the energy situation. We can't very well be talking about designing regulations to apply to new power plants, for example, that reflect what can be done using natural gas, if in fact, the use of natural gas is imprudent as far as national energy policy is concerned.

SESSION IV

COAL SUPPLY AND TRANSPORT FOR CALIFORNIA

D10

COAL SUPPLY FOR CALIFORNIA

Joseph J. Yancik
Vice President - Research,
National Coal Association
and
Chairman of the Board,
Bituminous Coal Research, Inc.

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The potential sources and qualities of coals available for major utility and industrial consumers in California are examined and analyzed with respect to those factors that would affect the reliability of supplies. Other considerations, such as the requirements and assurances needed by the coal producers to enter into long-term contracts and dedicate large reserves of coal to these contracts are also discussed. Present and potential future mining constraints on coal mine operators are identified and analyzed with respect to their effect on availability of supply. This paper concludes, based on a review of existing and planned new mine expansions and new mines in the western states, that adequate coal supplies are available to serve a major power generation market in California.

As I began to examine in more detail the potential coal supplies available for electric power generation in California, I soon became aware that this subject has been extensively studied and reported on by the Energy Resources Commission of the State of California, as well as many others. And, I also found out that many coal companies have more than an academic interest in the California market potential for their western coal reserves. Since this subject has been so extensively explored, I began to wonder what kind of contribution I could make. After doing more homework to learn what others have already determined, it was abundantly clear to me that sufficient coal reserves to meet California's needs are available from known and commercially viable coal deposits in the western coal provinces and possibly from Alaska. Since I found no evidence that anyone is challenging this conclusion, I could, in good faith, end my presentation on this note and let the panel devote their time to the transportation issues which seem to be still debatable.

However, I do not intend to relinquish my time so readily because, in my analysis of the coal supply for California issue, I came away with the feeling that there are more important caveats which have to be stressed and attached to the conclusion that "adequate supplies" exist. Indeed, after hearing the on-going debate over California's future electric power generation fuel supply plans, I came to a conclusion that I could make a contribution to this conference and to the debate by

stressing one simple fact. A fact so simple, I run the risk of sounding inane. Yet, I will take that risk to point out that the existence of a potential coal source is not enough to make it available. There are a number of "ifs" which must be recognized and dealt with before coal can be shipped from a mine in the quantities needed for a large base load power plant. Coal producers are well aware of these "ifs" -- utilities need to know them as well as their consequences. The "ifs" I am referring to are those inherent in the mine development schedule or the timetable required to open up a mine and bring it to its full production rate. And these "ifs" can become critical matters because the timetable to bring on line a large coal-fired plant and the timetable to open a mine to supply the coal are nearly identical. Any delays in the mine development timetable mean a corresponding delay in getting the mine into production. And that's the bottom line of my message because, for many reasons it now takes essentially the same time to bring a new mine into full production as it takes to put on line an electricity generating plant. In my brief presentation, I will point out some of the factors which are responsible for this substantial lengthening of the mine development timetable and discuss the associated "ifs."

However, before I highlight the fluid milestones which are on the critical path towards routine deliveries of coal to a power plant, I feel duty bound to present a brief summary on where potential coal supplies exist. Actually, the potential source list is important in itself in that it makes a point fundamental to a mine development schedule. The point being that potential coal fields have a wide range of coal qualities, topologic and geologic conditions, all of which influence the mining plans. Since mine development time schedules are affected by these factors, a brief look at the more promising coal deposits will highlight their differences in these areas.

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I. POTENTIAL SOURCES OF COAL SUPPLY

An extensive investigation by the coal supply group in the UCLA-DWR study (Ref. 1) identified and analyzed 92 coal fields within 800 miles of Los Angeles as potential sources of coal. Only 17 of these fields met their final criteria of having recoverable reserves of 100 million tons (over the life of the power plant), necessary coal quality (low sulfur content), mineability, and proximity to transportation systems. A summary of the characteristics of these 17 coal fields is given in Table 1 (Ref. 2). Their locations and the existing railroads and pipeline network are shown in Figure 1 (Ref. 2). The UCLA study team concluded that, on the basis of availability and likelihood of development, the coal fields of Central Utah, Wyoming, and New Mexico were judged to be the most promising sources. Note, specifically, that the Utah mines would be underground and the Wyoming and New Mexico mines would be surface mines. Later on in this presentation, I will be discussing the differences in time to develop underground-versus-surface mines.

In a report recently released as part of the National Coal Utilization Assessment (NCUA) program, "Impacts of Future Coal Use in California" (Ref. 3), the Lawrence Berkley Laboratory (LBL) study group concluded that coal burned in California is expected to come primarily from deep mines in Utah. The coal quality assumed in the LBL assessment had a heat content of 12,000 Btu per pound, 0.8 percent sulfur, and 13 percent ash. From Table 1, we see that only underground mined coals meet these specifications. The Central Utah coal fields in the Price area typically meet or exceed in quality these specifications and adequate reserves are reported to be available for long-term contracts. In the UCLA-DWR study, these Utah coal fields are identified in Table 1 as Fields 4, 5, and 6. According to the NCUA report, Table 2, at the typical operating parameters of a 800 mw coal-fired power plant burning coal with a heat content of 12,000 Btu and 1 percent sulfur, about 2 million tons of coal would be consumed each year. Assuming a 40-year plant life, the total coal required is 80 million tons. Translating this quantity back to coal in the ground, or reserves, and calculating at a total recovery of 40 percent (a reasonable over-all recovery ratio for underground mines), a reserve of about 200 million tons would have to be dedicated to this power plant. This reserve figure on a proportional basis is almost 25 percent greater than that which was assumed adequate in the UCLA-DWR study for a 500 mw plant.

Perhaps a closer look at these coal fields will serve to highlight some of the wide differences in the character of these deposits and, therefore, the likelihood for meaningful differences in mine development schedules. A good case in point is

the Black Mesa, Arizona, coal field (Number 3 in Table 1). It has the potential to provide a quality coal that would meet the environmental standards achieved with the base case coal. In a report from the Arizona Bureau of Mines (Ref. 4), data were given and which data seem to justify taking a much closer look at this field (Table 3).

Indications are that Arizona's Black Mesa coal deposits with its high quality coals will, despite the present political situation, be further developed to meet the state's coal needs as well as those of the neighboring states, including California. However, significant coal supplies from these fields are not expected to be available until the 1990's.

One potential coal source that did not make the UCLA-DWR list is the Beluga coal fields in Alaska. The questions of Alaskan coal as a viable source of supply for California keeps coming up and, indeed, was investigated in the UCLA-DWR study. They concluded that at least in the near term, coal from Alaska could not be competitive in price with Utah coal and further, that the problems associated with the siting of a suitable coal port unloading and rail transfer shipment facility is substantial. Although it is difficult to argue against this conclusion, with the public facts available to us today, I do not believe Alaskan coals should be written off at this time. It may be premature. For example, an article in the 16 January 1978, ANCHORAGE TIMES (Ref. 5) reported that Placer Amex is proceeding with their plans to develop a mine in the Beluga coal field, producing from 6 to 10 million tons a year for markets on the West Coast and Japan, and possibly a mine-mouth generating facility.

The Beluga coal field is in the Cook Inlet sedimentary basin and is about 60 miles west of Anchorage. According to McGee (Ref. 6), it is believed to contain 2.4 billion tons of coal with about 400 million tons strippable using today's mining technology. The coal ranges in rank from sub-bituminous to lignite, 12 to 33 percent moisture, 13 to 25 percent ash, 7,200 to 8,900 in Btu content and sulfur content below 0.20 percent. It is interesting to note that Placer Amex's Beluga Coal Project Status report of December 1977, indicated the first coal to be mined will have about 20 percent moisture, 16 percent ash, 7,200 Btu and 0.18 percent sulfur. By coal washing, the Btu content would be raised to 7,500 Btu.

I believe it was useful in the UCLA-DWR study of coal availability to establish the basic coal quality specs that would be appropriate in a baseline case study of coal-fired power generation in California. However, I believe it is just as important to recognize that the model coal does not

preclude the use of coals having a lower Btu, or coals having higher sulfur contents. For any specific coal, the power plant design and the environmental requirements are interrelated with the specifications and burning characteristics of the coal. For this reason, the potential sources of coal supplies for California probably exceed those identified in Table 1. Again, all this just supports the conclusion I started with, that there are ample supplies of coal for California, if proper recognition is taken of the factors that are necessary to assure a reliable and economic supply at the time it is needed. Some of these "ifs" will now be discussed against the backdrop of adequate coal deposits from widely varying geographic areas with each area having their special economic and regulatory requirements. In most cases, these requirements have to be met in a time-specific sequential sequence. And most of these requirements are on the critical path.

To illustrate their overall impact, a large surface mine on federal lands would take from 12 to 14 years to develop to full production. For a large underground mine, the time frame could be extended another 3 to 5 years as the construction times are greater and run up to full production takes longer. A more detailed look at the major steps in the mine development process would also show that an early commitment by a utility is essential and that normally the commitment must be made shortly after the decision is made to build a coal plant. This commitment point is probably the most significant one in the entire time schedule because it gives the full speed ahead signal for all the other actions required by the mining company.

II. MAJOR STEPS IN THE MINE DEVELOPMENT PROCESS

If time were available, I would like to discuss the mine development process in the detail given in an excellent paper prepared by James R. Jones (Ref. 7). In this paper, Jones explains the ten major steps required to develop a surface mine in the West on federal lands. As shown in Figure 2 and explained in Jones' paper, he started out with a number of federal leases sufficient to constitute a logical mining unit. The market development phase can thus begin the second year. Now let us take a look at the situation where a company does not have any federal leases. Should a coal company today receive notice that a utility is seeking bids for a supply of coal with deliveries beginning in ten years, and if that company does not already have federal leases under their control, it would not be in a favorable position to respond to the utility's bid based on coal from federally leased lands--the owner of about 80 percent of western coal which California must rely on. Under the new Federal Coal Leasing Amendments Act of 1977 (FCLA) and the recent

judgement rendered under the NRDC v. Hughes suit, the earliest date that federal coal leasing can be resumed is now estimated to be in mid-1980. If these conditions prevail, they would preclude any company from bidding unless they were already well into the stage of delineating their coal reserves and the quality of the mineable coal. And these data can only come from an extensive drilling program. In other words, only those companies which had been willing to invest substantial capital in the hope that a market would develop would be in a reasonable position to render a bid to supply 2 to 3 million tons of coal per year for a power plant coming on stream in less than ten years. Another important factor to keep in mind is that the diligent development requirements under the FCLA of 1977 specify that 2½ percent of the total reserve in a logical mining unit must be mined by 1986 or the leases will revert back to the government. Therefore, companies holding undeveloped federal leases may soon be running out of time.

It would also appear in this hypothetical case, if the plant were to be sited in California, that the utility had already submitted their "Notice of Intent" which means that the plant criteria and the coal specifications would then be "locked in" and the number of potential suppliers would be reduced considerably. Even in this case, assuming a coal supplier had the necessary coal quality and reserves, and was actively seeking a market, the time required to proceed with the necessary federal and state permits, prepare an EIS, and secure all the necessary approvals would, in most western states, be a lengthy process filled with many uncertainties and "ifs" that will result in delays in the mine development schedule. Development of a mine to its full production in eight to ten years would be a very close race, even assuming that there were no delays in the entire process.

If all this sounds negative, I want to assure you that this is not my intent, nor my personal feeling. To prove to you that my optimism is based on solid ground, I have some statistics that clearly show that the coal industry and the utility industry are working together in other parts of this country and that they are committed to coal.

III. FUTURE COAL PRODUCTION

Each year the National Coal Association makes an annual study of the industry's plant for new mines and expanded production from existing operations. In the latest study, released in November 1977, the findings were:

Nationally: . 594 million tons annual production would be brought on line 1977-1985
this 594 million tons would come from

- 142 mines operating at the end of 1976, which plan to add additional annual production of 170 million tons through 1985.
- 190 new mines which would be opened 1977-1985 with an expected annual production of 424 million tons.

In the East: Expansion of 95 mines and the opening of 111 new mines would bring on line 199 million tons of new and replacement production in the 1977-1985 period.

Just over 155 million tons, 78.0 percent, would be mined underground; 44.5 million tons, or 22 percent, would be mined on the surface.

- 123 million tons, or 61.6 percent, of the new production will be for steam coal; 76.6 million tons, 38.4 percent, will be for metallurgical coal production.

- Almost all -- 92.6 percent or 76.6 million tons -- of the total planned new or replacement metallurgical production 1977-1985 would be in the East. Two eastern states, West Virginia and Alabama, account for 60 percent, 48 million tons of the planned metallurgical coal production.

In the West: Expansion of 47 mines and the opening of 79 new mines would add 394 million tons new production in 1977 through 1985. (This is new production as replacement is not a factor in the relatively new western coal industry.)

- Over 90 percent of the new production in the West, some 358.8 million tons, will be surface mines; 96.5 percent (388.2 million tons) will be for steam use, in utility boilers and industrial use.

- The 388.2 million tons planned new steam production in the West

represents over 75 percent of all reported steam coal production additions in the United States; 40 percent of the national steam coal total is scheduled to come from one state -- Wyoming.

Table 4 summarizes the new and replacement production which the National Coal Association study shows coming on line 1977-1985. A more detailed summary of the future production by states, by use and by type of mining is presented in Table 5.

A word of caution must be given on the use of these study results. First, the results do not represent the expansion plans of the entire coal industry. This study represents plans of coal producers which accounted for 65.6 percent of output in 1976, as well as most companies that are expected to become major coal producers by 1985. Second, the plans reported by companies are, in many instances, far from complete. Some firms did not consider their plans for the 1982-1985 period sufficiently firm to warrant specific identification. Additionally, it is believed that plans reported herein for western mines are more complete than are the plans for eastern mines.

The net effect of these caveats is that actual production additions, and thus the actual capability of the industry to produce coal, will be higher than the data reported would indicate.

IV. POWER GENERAL WITH COAL

As of April 1977, the utility industry reported to the Federal Power Commission that they would bring on line 250 new coal-fired power plants by 1985. These new units would consume an aggregated total of 390 million tons of coal. Adding this to the present amount of coal used, the utilities could require up to 850 million tons in 1985. The National Coal Association has projected a lower range, conservative figure of 820 million tons, since it appears reasonable that delays will occur in the construction schedules of these new plants.

V. CONSTRAINTS ON COAL PRODUCTION

In a preceding section, the optimism of the coal producers was demonstrated by their planning for new capacity to meet the expected substantial increase in demand. While their optimism is real, there is also the realization that extensive delays in expanding or opening new mines are likely to be encountered.

Heading the list of potentially constraining actions is the Surface Mining Control and Reclamation Act of 1977, because of its many unnecessary and costly impediments to mining. As mentioned

earlier in this report, the federal coal leasing program, or lack of one, is another serious concern to western coal producers. There are other constraints to coal production, such as the rigid application of the coal mine health and safety laws and regulations, labor-management relations, unauthorized work stoppages, productivity declines, and transportation bottlenecks. All of these constraints can and are being managed, but more consistent policies from and cooperation between the federal and state governments would do much to reduce these problems to a minimum.

VI. CONCLUSION

In closing these brief remarks, I once again emphasize what I said in my opening statement. There are adequate supplies of coal for power generation in California over the long term because there are enormous reserves of coal in the western states and Alaska. In the short term, there can be adequate supplies if the utilities proposing to build coal-fired plants secure a commitment of commercially viable reserves that can be developed within the same time frame it takes to construct the power plant. The prospects are bright that California will call on coal to provide a greater share of its energy needs in the future and that many coal producers are standing by ready to help California reach that goal.

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Table 1. Summary of Coal Source Quality and Cost
Quality

Field	Mining Method	Ash (Percent)	Sulfur	Heat Content (Btu/lb)	Estimated 1976 Cost (f.o.b. mine)	
					(\$/ton)	(\$/mmBtu)
1) Alton, UT	Surf	9.6	1.3	10,772	5.00	23.21
2) Kaiparowits Plateau, UT	Ug	8.96	0.87	11,999	11.00	45.84
3) Black Mesa, AR	Surf	10.9	0.40	10,825	3.09	14.26
4) Book Cliffs, UT	Ug	6.7	0.85	12,762	10.00	39.18
5) Wasatch Plateau, UT	Ug	6.5	0.60	12,589	10.00	48.14
6) Emery, UT	Jg	8.9	0.99	11,424	12.00	28.20
7) Gallup, NM	Surf	7.95	0.42	10,637	6.00	23.68
8) Star Lake, NM	Surf	20	0.6	9,500	4.50	54.55
9) Sego, UT	Ug	11.1	0.60	11,000	12.00	60.87
Book Cliffs, CO						
10) Somerset, CO	Ug	8	0.6	11,500	14.00	58.33
11) Grand Hogback, CO	Ug	8	0.6	12,000	14.00	33.02
Carbondale, CO						
12) Yampa, CO	Surf	10.53	0.47	10,598	7.00	36.62
13) Kemmerer, WY	Surf	7.89	0.50	9,683	7.09	57.52
14) Evanston, WY	Ug	7.2	0.4	10,450	12.00	57.42
15) Rock Springs, WY	Surf	10.58	0.60	9,210	4.55	24.72
16) Great Divide, WY	Surf	10	0.9	10,500	5.00	23.81
Little Snake River, WY						
17) Hanna, WY	Surf	6	0.6	10,500	5.00	23.81

Table 2. Characteristics of Coal Source Quality and Cost

	Conventional Combustion	Atmospheric Fluidized Bed
Capacity	800	800
Capacity Factor (percent)	75	75
Heat Rate (Btu/kWh)	9500	9500
Efficiency	0.359	0.357
Energy Input (10^{12} Btu/yr)	50.0	50.2
Coal Input (10^6 tons/yr)	2.08	2.09
Heat Rejected (10^{12} Btu/yr)	32	32.3
Water Evaporated (ac-ft/yr)	9650	9750
Make-up Water (ac-ft/yr)	10859	10930
SO ₂ Emission (10^3 tons/yr)	4.14	4.18
NO _x Emission (10^3 tons/yr)	17.5 ^a	12.0
Particulates (10^3 tons/yr)	1.76	2.5
Solid Waste (10^3 tons/yr)	600	450 ^b

^a Based on EPA New Source Performance Standards.

^b Assuming no sorbent regeneration.

Table 3. Characteristics of Black Mesa Coal
Estimated Gross Coal Resources of Black Mesa

	Billions of short tons	Utilization
Wepo Formation	5.65	Presently being mined
Toreva Formation	6.00	Small Mines - inoperative
Dakota Sandstone	9.60	Small Mines - inoperative

Quality and Heat Content of Black Mesa Coals

	Dakota Coal	Toreva Coal	Wepo Coal
Average Ash (%)	11.9	13.8	5.27
Average Sulfur	1.62	1.09	0.58
Average Btu/lb	11,125	12,338	12,382

Table 4. New Production ^{1/} at Mines Covered in This Summary, 1977-1985

	East	West (Millions of Tons)	Total
Use:			
Steam	123.6	388.2	511.2
Metallurgical	76.6	6.2	82.8
Type of Mining:			
Surface	44.5	358.8	403.3
Underground	155.1	35.6	190.7
Total	199.6	394.4	594.0

^{1/} Includes both new and replacement production.

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State Summary, by Use and Type of Mining (Millions of Tons)
Expected Incremental Production at Mines Listed, 1977-1985

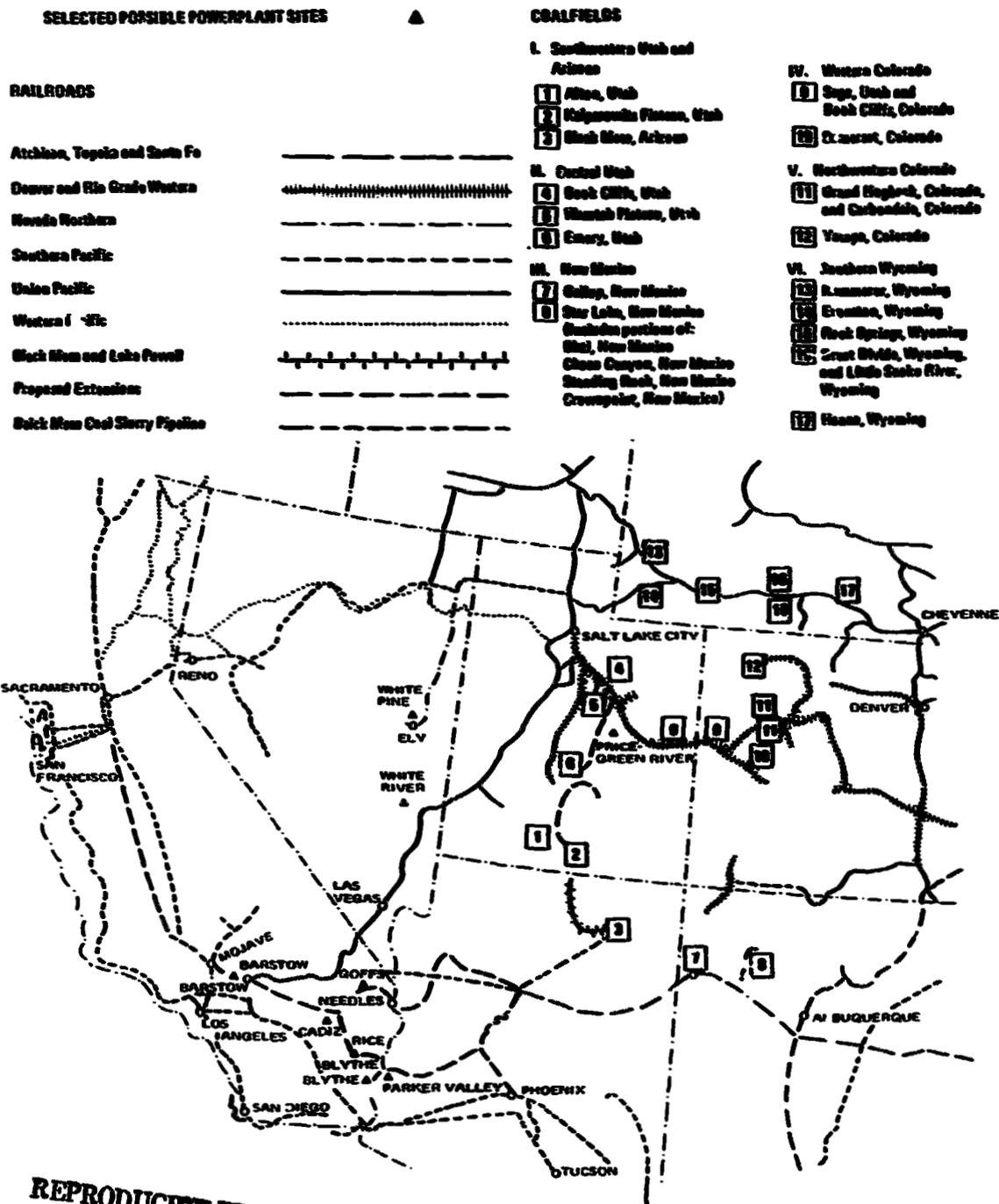
State	Total Production At Mines Listed 1976	Use		Type of Mining		Total Incremental Production 1/	Total Expected Production 2/ at Full Operation
		Steam	Metallurgical	Underground	Surface		
Alabama	2,525	7,901	13,324	17,725	3,500	21,225	23,750
Illinois	5,752	29,948	1,250	23,224	7,974	31,198	36,950
Indiana	6,387	11,413	--	--	11,413	11,413	17,800
Kentucky, Eastern	2,348	16,612	7,490	15,702	8,400	24,102	26,450
Kentucky, Western	1,623	17,877	--	28,281	5,296	17,877	19,500
Kentucky, Total	3,971	34,489	7,490	41,979	13,696	41,979	45,950
Maryland	--	--	2,000	2,000	--	2,000	2,000
Ohio	3,586	11,214 3/	--	8,714	2,500	11,214	14,800
Pennsylvania	3,806	12,449	11,775	23,047	1,197	24,244	28,050
Tennessee	0,490	0,800	0,810	1,610	--	1,610	2,100
Virginia	--	0,750	5,200	5,950	--	5,950	5,950
West Virginia	5,918	14,039	34,681	44,491	4,231	48,722	56,640
Total East	32,435	123,003 3/	76,572	155,044	44,511	199,555	231,990
West							
Arizona	4,667	3,333	--	--	3,333	3,333	8,000
Arkansas	--	--	0,200	0,200	--	0,200	0,200
Colorado	3,908	16,430	3,962	11,680	8,712	20,392	24,300
Iowa	0,100	0,100	--	0,100	--	0,100	0,100
Kansas	--	0,250	--	--	0,250	0,250	0,250
Montana	23,556	65,144	--	--	65,144	65,144	88,700
New Mexico	9,331	11,169	0,500	--	11,669	11,669	21,000
North Dakota	9,714	25,136	--	--	25,136	25,136	34,850
Oklahoma	--	6,650	1,500	1,500	0,650	2,150	2,150
Texas	8,400	35,700	--	--	35,700	35,700	44,100
Utah	4,265	23,235	--	17,735	5,500	23,235	27,500
Washington	4,023	2,977	--	1,000	1,977	2,977	7,000
Wyoming	19,878	206,122	--	3,400	200,722	204,122	244,000
Total West	87,662	386,246	6,262	35,615	358,793	394,408	487,237
Total United States	120,277	511,249 3/	82,734	190,659	403,304	593,963	714,240

1/ Excludes 1976 production from mines operating in 1976. This total includes only expected incremental production from expansion of existing mines and production from new mines 1977-1985.

2/ This figure includes 1976 production levels and represents total expected annual production at full operation.

3/ Includes 2.5 million tons for gasification.

Note: All totals include some data which has not been verified by NCA.



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Figure 1. Southwestern railroads and coalfields

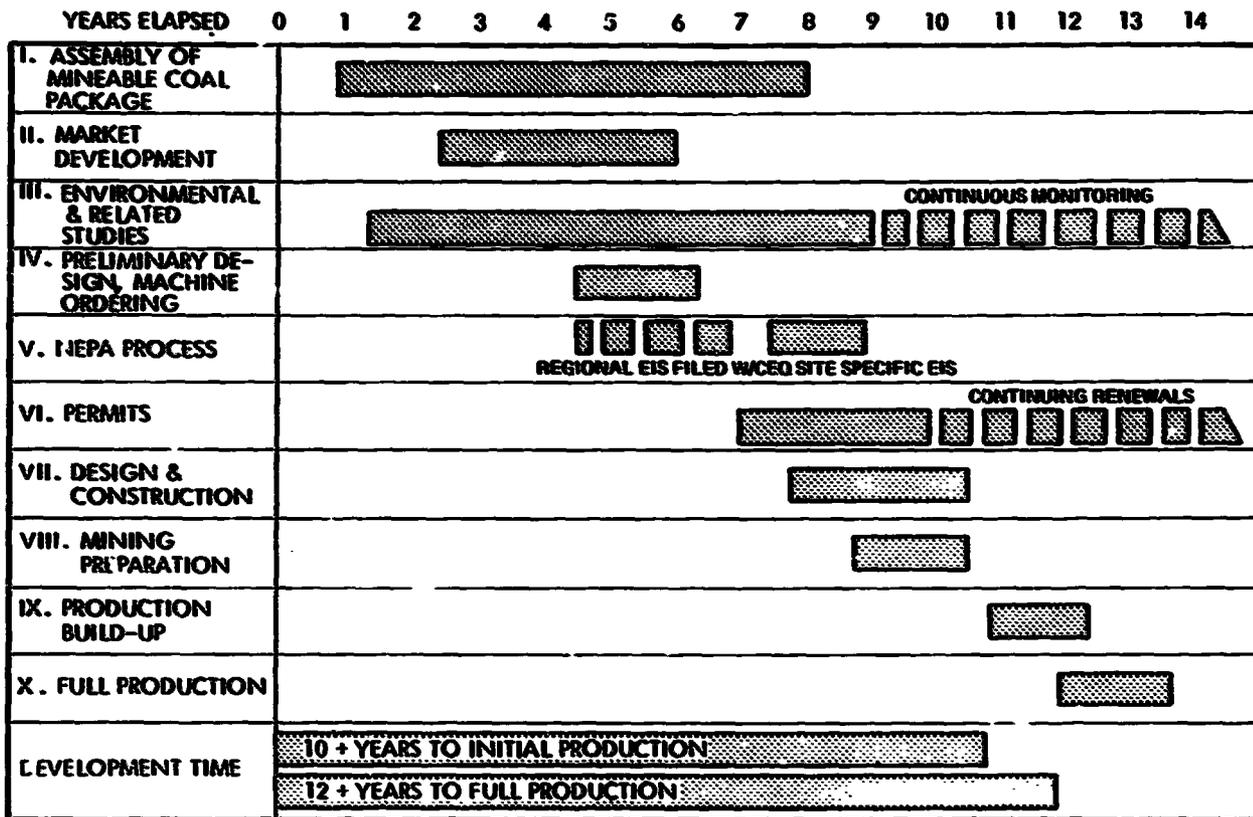


Figure 2. Illustrative surface mine development schedule (Federal Coal-West)

OMIT

**CONVENTIONAL AND UNIT TRAIN COAL TRANSPORTATION
OF COAL BY RAIL**

F. M. Guerin

Assistant Vice-President

**Southern Pacific Transportation Company
Los Angeles, California**

While Southern Pacific has not traditionally been a primary carrier of coal traffic, a number of recent changes have made coal a much more important commodity in SP's mix of transportation products.

Coal originates in volume in such states as Colorado, Utah, Wyoming, and New Mexico, and is moving in increasing volumes via SP to major electrical generating plants and heavy industrial processing users. Also, a large number of export coal movements via California are currently in various stages of study and development.

Most of these large volume movements involve unit train operations, often with 100 tons per carload and 100 cars per train. Highly-mechanized, rapid unloading facilities are used regularly to increase the productivity of these expensive assets.

With the changing emphasis placed upon environmental pollution, control of available alternative fuel sources and related economics involved, it can well be expected that California will be using substantially larger amounts of coal in the future. As California's coal deposits are minimal, the expectation that large volumes will be moving from such states as those listed above can well be anticipated.

SP has a wholly-owned subsidiary known as Black Mesa Pipeline Co., which operates a 270-mile coal slurry pipeline from Kayenta, Arizona, to Davis Dam, California. This particular operation pumps coal in ground-up form mixed with water using only four large displacement pumping stations along its 270-mile route. This particular technology has been very successful in transporting large volumes of coal without adverse effects on the environment or related pollution problems and, in fact, the water is even recycled in such a manner as to be put back into the Colorado River without contamination problems.

California's growing demand for energy can well be expected to involve additional coal requirements. Coal can be technologically transported by rail successfully and in turn converted into electrical energy under economically viable programs.

While certain research activities dealing with coal gasification and other emerging technology may displace some transportation of coal by rail, it is now too early to have definitive conclusions on this subject.

Southern Pacific Transportation Company has substantial capacity to handle large volumes of coal to California destinations where, in fact, studies and preliminary indications have revealed that this basic source of energy will be used in large volume within the next decade.

Southern Pacific Transportation Company during 1977 handled approximately 3-million tons of coal with the preponderance involving the unit train operation from the Gillette, Wyoming, area to San Antonio, Texas. This particular movement commenced in October of 1976. A second unit coal train operation started in September of last year from Gallup, New Mexico, to Trona, California. As an intermediate carrier, we handle the trains from Mojave to Searles. A third unit train movement of coal is scheduled to commence on July 1 of this year or some time shortly thereafter, and this will also originate from Gallup, New Mexico, but will move to the facility of Arizona Electric Power Cooperative Company at Cochise, Arizona. We will handle the train from Deming to Cochise. Another unit coal train on the horizon will be from Craig, Colorado, to the facility of Central Power and Light Company of Corpus Christi, Texas -- at a point called Coleta Creek, Texas, which is scheduled to start moving during the third or fourth quarter of 1979.

The above are a few examples of the current and immediate future coal transportation picture for Southern Pacific. As you can see, our role is not that of an origin line since we do not serve any of the western hard coal deposits and thus our role is that of an intermediate or destination carrier.

Future demand for coal can well be expected to involve large volumes moving consistently between the same source and destination points in unit train volumes over long time periods. This may involve moves such as from a coal mine to an electrical power generating plant.

Future smaller volume coal traffic patterns can well be expected to be of a repetitive nature, but will involve more source area and a wider variety of end industrial uses. These particular volumes may move in conventional rail carload-type service or under certain conditions be unit train-type operations.

It can well be predicted that there will be smaller industrial plants using coal for primary or secondary generation purposes. These will involve multiple origin and destination points, varying time periods, volumes, quality of coal, etc. It is expected that most of this traffic would move in conventional open hopper-type cars.

Future coal transportation by rail involves several possibilities of equipment ownership, including rail carriers, mining companies, consignees and/or other parties. Substantial differences in utilization level, economies of scale in equipment utilization and acquisition will be dealt with on a case-by-case basis as need arises.

In summary, the California railroads, including SP, have substantial unutilized plant capacity and a willingness and interest in profitably transporting large volumes of coal for domestic use or for export as needed.

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PROSPECTS FOR COAL SLURRY PIPELINES
IN CALIFORNIA

N79-27608

John F. Lynch
President
Energy Transportation Systems, Inc.
San Francisco, California

I. INTRODUCTION

An important new segment of the transport industry is emerging in the United States. It is accepted that it will play a vital role in meeting America's urgent energy requirements without public subsidy, tax relief, or federal grants.

It is a proven technology, ideally suited to transport of an abundant energy resource over thousands of miles to energy-short industrial centers and at more than competitive costs.

It is an "idea whose time has come," the coal slurry pipeline, a coal delivery system designed to link plentiful western coal reserves with electric power plants in the Midwest, Mid-south, Southwest and Far West regions, much as oil and gas are now moved by the 500,000 mile network in this country.

While relatively new to the general public, the slurry pipeline concept has been an important part of the world's commodity transportation picture for many years. In fact, the first U.S. coal slurry patent was granted in 1891 to Wallace C. Andrews, who had exhibited a working model of his slurry pipeline system at the Columbia World's Fair in Chicago in 1890 and constructed a pilot plant in New York City.

The first practical application to contemporary transportation requirements came in 1957 when the Ohio Coal Pipeline began operations. This system ran successfully for six years. Its economical operation had served to force down rail rates for coal deliveries from that part of the country.

Other slurry pipelines around the world in over 14 different locations have proven to be a most economical method for transporting other important raw materials such as copper, magnetite and nickel ore. One such pipeline has been operating since 1972 in California's Gold Country, pumping limestone slurry 17.6 miles from Flintkote Company's Cataract quarry to its Calaveras Cement Division plant at San Andreas.

Completely hidden from view, the Calaveras pipeline transports the slurry silently, safely, and reliably while preserving the beauty of its Mother Lode setting and eliminating the need for large numbers of trucks to haul the limestone.

Consumers in Southern California also benefit from the best example of coal transport efficiency in the United States. The Black Mesa pipeline, which is the world's longest coal slurry pipeline system in operation carries five million tons of coal a year from northeast Arizona to the Mohave power plant in southern Nevada, a distance of 273 miles over rough and mountainous terrain.

Operated for Southern California Edison, this pipeline has been in continuous use since 1970.

This system's track record has been excellent. Jack K. Horton, Chairman of the Board of Southern California Edison, has stated, "...our experience to date indicates that the Black Mesa pipeline has transported coal to the Mohave Plant at a cost benefit of nearly 50 percent below that of alternative transportation costs."

He also pointed out that from the time the pipeline began commercial operation on November 1, 1970, it has demonstrated a reliability factor of better than 99 percent.

Simplicity is the coal slurry pipeline's chief asset. The 2' x 0' coal is received from the mine, cleaned, crushed and then mixed with water to be pipelined to its destination. In all respects the pipeline construction itself is conventional, including the pumping stations which use standard off-the-shelf equipment items.

At the discharge end, the coal is dewatered by centrifuge. The water is clarified and used in the cooling tower circuit. The coal is delivered by belt and is utilized in the boiler, much as rail coal would be.

II. CALIFORNIA MARKET POTENTIAL

In California, as elsewhere in the United States, electric utilities are seeking other fuel sources to replace dwindling reserves of natural gas and high priced imported oil. Nuclear power, which initially seemed to be such a bright prospect, has dimmed in the face of increasing costs and regulatory delay.

A recent study undertaken by the Office of Technology Assessment (OTA), the research arm of Congress, has forecast that the demand for coal in California will grow from less than

one million tons per year in 1980 to 39 million tons annually in the year 2000. Much of this coal is expected to come from distant reserves in Utah and Wyoming, traversing mountain and deserts to reach urban and industrial centers.

The study also looked at several movements of coal to markets throughout the Western states and reached some pertinent conclusions including: pipelines are more economical than rail for long-distance, large-quantity hauls; for other situations, pipelines are competitive on a case-by-case basis.

In citing a hypothetical case wherein slurry and rail coal transportation were directly compared on a routing between Wyoming and Texas the OTA found in this long-distance, large-quantity (35 million tons a year) example that slurry was definitely the better way on several counts.

The study reported that the most direct railroad routing possible in this sample case--from Gillette, Wyoming to Houston--would be 1,584 miles, compared to only 1,170 miles for a slurry pipeline to connect the two points. Covering that additional 400 plus miles costs money, of course, and the sheer distance advantage the slurry pipeline would have, in addition to the many other cost-effective factors in favor of the pipelines, resulted in a significant bottom-line finding by the OTA.

In this hypothetical case, the OTA study reported that the per-ton cost of moving coal by pipeline over the Wyoming-Texas routing would be \$6.50, compared to \$9.10 by rail. It is this kind of dramatic cost difference which begins to make economic sense for the shipment of coal by slurry pipeline--in the minds of utilities, industrial users and, most importantly, the ultimate consumer.

In another hypothetical case, the OTA made a comparison from Utah to California and found that an equivalent rail routing would be 30 percent longer than pipeline and would require replacement of 25 percent of the present rail system to meet new operating requirements. However, in this case, which would involve the shipment of only 10 million tons of coal a year over a much shorter distance from Price, Utah to Barstow, California, the per ton shipping cost favored rail, pointing up the fact that pipelines are superior over the long haul involving large quantities. Even with the shorter distance involved in the Utah-California case (684 miles by rail, 522 miles by pipeline) we are confident that the economics would have favored pipeline if the amount of coal to be shipped was significantly larger.

III. SLURRY TECHNOLOGY - NEW EFFICIENCIES

By way of background, the electric utility industry from 1925 to 1970 maintained a remarkable stability in its rates brought about by efficiency of power generation. In fact, the electricity rates for residential consumers actually decreased 70 percent during this period, while the Consumer Price Index rose 500 percent.

By building ever larger and more efficient power plants, less fuel was needed to produce a given quantity of electricity. Enormous gains in the size of the boiler units kept the cost of kilowatt hours extremely stable over a long period of time.

In the 1970's, however, generators began reaching practical size limits and formerly predictable fuel costs began soaring. Western coal reserves have emerged as an abundant and relatively inexpensive energy source which can once again restore stability to the cost of kilowatt hours.

The key to economical use of Western coal lies in transportation costs which will run as high as 70 percent of the delivered cost of fuel. For this reason, coal slurry pipelines offer the technological breakthrough in economies of scale necessary to transport coal over long distances while maintaining reasonable electric rates.

In the Far West, with substantial distances between coal reserves and the end-user, the economies of scale gain added significance. As proven time and time again, the larger the system, the more competitive the pipeline over rail transport. This conclusion has been confirmed by the previously mentioned OTA study.

In contrast there is practically no economy of scale for the railroads which will carry the burden of most coal transport. A unit train set of 110 cars at 100 tons per car will move 11,000 tons per trip. If a trip takes five days one way for a 1,000-mile movement, then by definition one train set would move about 400,000 tons per year. Additional tonnage above this level merely calls for additional train sets.

Pipelines in general enjoy a much lower inflation sensitivity than rail transport because 70 percent of its costs are fixed. Once the pipeline is installed, only 30 percent of operating expenses are subject to increases in the cost of labor, electric power and supplies.

In the case of rail, the reverse is true. Between 75 and 80 percent of its costs are variable with inflation. For instance, more than half of rail expenses are tied to the cost of labor and are consequently subject to the volatile impact of labor disputes and strikes, not to mention

higher operating and maintenance expenses.

Pipelines use about one-eighth the labor, 40 percent less steel over a 30 year period and, for items such as supplies, two to three times less the dollar amount per ton of coal moved.

Production in the Western coal reserves is forecast to jump by at least 300 percent between now and 1990. The OTA study estimates that by 1985, the railroads will need to acquire 9,100 locomotives, 197,000 new coal cars and 350,000 other freight cars to meet expanded coal delivery requirements.

Additional expenditures to upgrade badly-deteriorated rails, roadbeds and grade crossings--for which the railroads are seeking substantial government subsidies--clearly make it impossible for the railroads to handle such a massive undertaking on an economic basis.

In the western states, coal slurry pipelines are expected to carry about 25 percent of total coal traffic by the turn of the century, thereby providing an urgently needed and economical supplement to rail transport.

IV. ENVIRONMENTAL BENEFITS

Environmental considerations present another powerful argument in favor of coal slurry pipelines in such states as California which are fighting to preserve the inherent beauty of the land. The slurry system is underground, it is silent and invisible, and it doesn't disturb nature or interfere with the lives of people in the region where it operates. Pipeline construction is brief and the land is restored to productive use.

These positive factors are weighed against the unpleasant side effects of steady coal train traffic through communities. For example, the Burlington Northern has estimated that by 1980 it will be operating 84 coal trains a day, including returning empties, over the four routes out of the Powder River Basin in Wyoming. If evenly divided among the four routes, this adds up to mile long unit trains moving along the rails at one-hour intervals, day and night, constantly interrupting the flow of automobile and pedestrian traffic and interfering with emergency services across the tracks which bisect many Western communities. The noise, vibration, the dust, and smoke will also have their impact.

V. HEALTHY COMPETITION

When all pros and cons of the coal slurry pipeline are taken into consideration, the introduction of healthy competition might well be the system's chief contribution to the Western states. Lacking even barge competition, Western carriers have been able to charge just about what they choose to transport coal. As slurry pipelines are built,

railroad management will have to consider competitive forces in setting their rates, just as in other parts of the country.

In recent years, utilities have been experiencing difficulties with the railroads during tariff negotiations. For instance, several utilities have lawsuits against the Burlington Northern necessitated by the "take it or leave it" attitude engaged by that railroad in setting tariffs. A utility executive, in a sworn statement before the ICC, summed up his frustration with BN's "arbitrary increases above and beyond escalation," by saying, "Certainly, it is not inflation. Unreasonable exploitation of a monopolistic advantage is undoubtedly a more realistic explanation." (ICC Docket No. 36719)

The injection of coal slurry pipelines into this monopoly will provide the head-to-head competition which will force the railroads to adopt a more equitable rate-making posture and result in savings for Western consumers.

One clear perspective on how this might come about was voiced recently by Betty Jo Christian, Vice Chairman of the Interstate Commerce Commission. In a public address she stated:

"It is worth noting that there is one potential pricing restraint of major proportions currently looming over the developing Western coal market. I am speaking, of course, of the proposals for pipelines to carry coal in slurry form from the Western mines to large utility and commercial users."

Ms. Christian continued:

"The existence of a competing form of transportation for Western coal would put the whole subject of railroad rates on coal in an entirely different context... The situation as it exists today (is that) the railroads possess a virtual monopoly over large-scale, long distance coal traffic--and I can only offer the caveat that, if and when slurry pipelines make their appearance, our entire approach to railroad rate-making will have to be re-examined."

Ms. Christian has put her finger on one of the key points in the pipeline versus rail debate: From an economic standpoint alone the railroads cannot be allowed to continue their dictatorial stranglehold on the movement of coal in this country.

VI. THE ETSI PIPELINE

Movement of coal from the Western reserves via slurry pipeline will be achieved by Energy Transportation Systems Inc. Plans are well underway for a 1400-mile pipeline from the Powder River Basin coal fields in Wyoming to

utility and industrial customers in the Midsouth region, ultimately terminating on the Mississippi River in Arkansas and Louisiana.

This region, which has been dependent upon natural gas for decades, is experiencing the pressures of disappearing gas reserves and sharply higher prices for imported oil. Plans to convert from oil and natural gas to coal as fuel for electric generating facilities makes coal slurry transport an increasingly attractive alternative, not only for the Midsouth but for California as well.

The ETSI pipeline will be financed entirely with private capital and will require no government financial support. It will ship 25 million tons of coal annually under long-term contracts with customers along the route. A major customer is expected to be Middle South Utilities, which operates an extensive electric generating system in that area. The pipeline also has the flexibility to adapt for deliveries to other utilities and for trans-shipment by barge for deliveries on the lower Mississippi.

Important economic benefits will accrue to consumers along the route. It is estimated that a typical 750 megawatt generating unit can save about \$1 to \$1.5 billion in transportation costs by using a coal pipeline for 30 years. The ETSI pipeline has the capacity to supply 10 such units, for a potential saving of \$10-15 billion.

With the implementation of the ETSI system, coal slurry pipelines will be given a chance to prove their worth in the marketplace. As the benefits of this mode of transportation become more widely recognized, we project that more states will opt to include the coal slurry pipeline in their list of top energy-related priorities, including California.

Certainly the stability of pipeline costs over time will do much to permit stable energy prices, which in turn will allow our manufactured products to be competitive in the world market, and to reduce our dependence on foreign oil which will improve our trade balance and the value of our dollar--at home and overseas. In the long run, the ultimate beneficiaries will be the public and the taxpayer, adding impetus to the widespread acceptance of an idea whose time has come.

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SESSION IV: COAL SUPPLY AND TRANSPORT FOR CALIFORNIA

Session Cochairmen: Orson Anderson (UCLA)
Milt Lavin (JPL)

Speakers: Joseph Yancik (Bituminous Coal Research, Inc.)
Frank Guerin (SP)
John Lynch (ETSI)

OPEN DISCUSSION BY ATTENDEES

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UNIDENTIFIED ATTENDEE

Have studies been conducted for the energy comparison of coal slurry pipelines vs. unit trains?

JOHN LYNCH

We have and so has the OTA study. I don't have the facts right at my fingertip, but I believe that the amount of energy per ton of coal transported is in favor of the railroad. I'm not absolutely sure, but I don't think it is significant.

MIKE ROGOZEN

I'm with Science Applications, Inc. at UCLA. I performed the environmental assessment part of the OTA study. In answer to the energy question, you are right, the pipelines use slightly more energy per ton transported, but you have to take into account the distance of the route and the amount hauled. You can't flatly say one uses more or less than the other.

Mr. Guerin said something that was in error about the disposal of the water at the Mojave Plant, after it is reused in the power plant cooling system. It is disposed of in ponds and it is not put into the Colorado River. They

don't have a discharge permit for the river and for that reason the seepage from the disposal ponds is monitored to make sure that it doesn't get into the river.

I have a question for Mr. Lynch. If the ETSI pipeline transfers coal to barges, will the coal be dewatered, and, if so, where will the water go if it is at the Mississippi River?

JOHN LYNCH

The plan is that the barge terminal, if there is to be a barge terminal, would be adjacent to an electric utility plant. The concept is that the water would be used in their cooling circuit; however, the coal slurry for barge transport would not be deep watered to the same extent that it would have, had it been fired directly into a plant at the site.

PETER FLAREY

I'm with the California Counsel for Environmental and Economic Balance. I have a question for Mr. Guerin. When you indicate that you have relatively few problems with the transport of coal, how do you plan to deal with the air emissions, both from the coal being transported and, from the increased use of trains, the locomotives themselves?

FRANK GUERIN

There is probably no way we can deal with it. If you are going to transport something, you are going to use energy and there are going to be emissions. The locomotives that we would propose to handle unit trains would be new locomotives, the best you could buy with the manufacturers at that particular time and as far as any pollution, from moving coal to my knowledge, is insignificant.

RON RUDOLPH

I'm with Friends of the Earth, and I would like to clarify something Prof. Anderson said. In your opening remarks, you implied that the designation of wilderness on the Kaiparowitz Plateau would be the biggest constraint to develop the sizable coal reserves there. I would argue that given the political climate in Utah, it is unlikely that there will be any wilderness designation on the Kaiparowitz Plateau. But regardless of that, the UCLA study which you coordinated, rated the top 20 coal areas for California in terms of cost and the Kaiparowitz Plateau did not fall into any one of these 20. I would argue that it would be economics, and not wilderness, which would prevent the development of that coal field in the near term. I was wondering if you had a comment on this.

ORSON ANDERSON

You have to look at the problems on two different scales. The UCLA study was answering the question, How would you get 1000 megawatts of coal fired energy in California? What would you do is, you would find the most available coal and Kaiparowitz Plateau is out of the running. On the other hand, if you ask the question, "How are you going to get one hundred million tons to California per year?," then you have to go to the Kaiparowitz Plateau, or places like it, that are undeveloped. The question that I'm talking about there is, will the leases be available for the new places that have to be developed at this new order of magnitude scale? So remember that the UCLA study was for just the first increment of this new California policy announced by Brown.

RUSS MINER

I'm with the California Energy Commission. Mr. Yancik, in his very interesting talk, pointed to a problem area that I would like to understand a little bit better. I reviewed several other studies that concur with his conclusion that coal mine development really is the critical time path in terms of developing a new coal plant. Talking in terms of 10 to 12 years from partial to full production for a new coal plant in terms of getting the coal

on site and in a position where it can be burned, I'm wondering whether the panelists could comment, or perhaps, one of the utility representatives here could comment, as to whether the 1500 megawatt coal plant that has been announced by SCE in Southern California and the 1000 megawatt plant the DWR has announced, have an identified coal supply that is in the process of being planned or whether that work yet remains to be done. If it is the latter, i.e., if the mine development is just starting, it would appear to me, that those units would not be on line until about 1990, at the earliest, so I would like to have either a panelist or perhaps someone from the utility comment on that.

The second question that I would like to ask is related to Mr. Lynch's very interesting comments about the benefits of slurry pipelines. However, it is my understanding that in order to build slurry pipelines, right of ways are necessary particularly where they cross existing rail lines or perhaps proposed rail lines. I don't wish to start an argument but I would like to know whether this really is a practical constraint on slurry pipelines in California because we need to address this issue very quickly.

JOSKPH

I'll start off by saying that I don't know.

ORSON ANDERSON

Is there someone here from one of the utilities that would like to comment on the first question.

TERRY THOMPSON

I'm with the Southern California Edison Company. The coal resource for those projected projects has not been settled on. It's as Dr. Anderson says, the most economic source would probably be the one used.

JOHN SPAULDING

I'm with Kaiser Engineers. Not being from a utility, but to address the question on timing of coal mining openings; I believe

the length of time for underground coal mine openings was a little bit long or misleading. I believe that major underground projects, in the size range of 8 to 12 million annual tons, can be brought on line in 8 to 10 years of construction time as long as the permitting has been done. Also, the first increment 's production, which may be as much as 25 to 35%, can be on line in 6 years.

RUSS MINER

It seems to me that we have a chicken and an egg situation here where a coal operator is not going to make a commitment to invest his money until he is assured that he has a customer, the customer can't really make a commitment until he is sure that he has a site, and approval of the utility commission. I'm wondering if Dr. Yancik might have some insight into what assurances a coal operator really has to have before he will go ahead and seriously begin to develop a property. In the western states where federal lands are generally involved, the first step is for a company to assemble a package of leases that can be constructed into a logical mining unit with sufficient reserves to meet the needs of a major utility customer. The operator will define these reserves to the point where he considers them to be an economic and salable package to the utility consumer. This definition generally doesn't mean that they've done all of the extensive close center dulling that's going to be required to determine the properties of the coal for boiler design. To get this data, an operator would have to make a very large capital commitment. Most operators would want to have some type of letter of intent or other type of contractual agreement with a utility to proceed from that point.

ORSON ANDERSON

OK, let's move on to the second part. John Lynch?

JOHN LYNCH

The question was, the railroad crossing or just the whole right of way problem. It's the whole right of way problem, basically. There are three areas where you can be active in order to assure yourself that you can get the right of way. Of course, we

wouldn't proceed unless we had had very sound assurances that we could get the right of way.

At the federal level, through the Slurry Transportation Association, (it is a national association of some 700 members) we have been active in Washington. There is the Ekhart Bill, Congressmen from Texas, House Rule 1401 or 1501 or some number like that. It is making progress; on Tuesday of this week, it was voted 13 to 10, in our favor, out of the Public Works Commission at the Department of Interior and it is now scheduled, without a date established to go to the full Interior hearing. We believe we will receive favorable action. That's at the federal level.

At the state level we have been active and in each of the states that we have... as of this moment, we have the right of eminent domain which means the right to condemn property, if you will, private property, and place the pipeline after paying proper compensation to the land owners. The same right would give us the right to cross the railroad, and we have that right in the states of Wyoming, Oklahoma, Texas, Arkansas and Louisiana. In Kansas and Nebraska we are active in the legislature.

On the grass roots level, we call the window program, we have sued the railroads on 70 different occasions to cross their rights (the rights that they say they have). These rights were provided them in the Act of 1862 and again in 1875 when our transcontinental rail system was built. I think the most important ruling was a summary judgement, issued by Judge Bremmer in Cheyenne, the 13th Federal Court, which said that the intent of those Acts was not to build a barrier across our nation but to provide a means of connecting the East and West. We have won all but 8 of the 70 cases, one of them, a UP crossing is being appealed. We anticipate we will enter a consent decree with one of the major railroads on three of the remaining crossings and my current projection is that, by mid-year, we will have all of the railroad crossings we need because of the actions of the Federal Courts.

MARK ZIERING

I'm from the California Energy Commission. I have one question on railroads and one question on slurries. The question on railroads regards a recent task force report, out of the Department of Transportation, which pointed out that much of the western railroad network was constructed to carry grain shipments. Therefore, most of the track (or a good part of the track) is about 90 pound weight. The report suggested that more appropriate weight for coal transport would be 130 pounds. I would like to ask Mr. Guerin how much of the SP system is of insufficient weight to carry heavy coal train traffic. What can the company do about that and has he any observations on the general state of western railroads to carry this kind of traffic.

The other question is on slurry pipelines and it seems to me that one of the problems in using a slurry pipeline in California is that they require a large throughput of coal. The OTA study estimated roughly that 17 million tons of coal would be required from Utah to California yearly to justify construction of a slurry pipeline. That means that you have to have a very concentrated source of coal and also a very concentrated use pattern in California. I would like to hear comments either from the panel or from the audience on the problems of getting that kind of concentrated source of coal. Also, would concentrated use, say 17 million tons in one area, cause serious air pollution problems?

The other question is that, if in fact, it would cause air pollution problems, can you subdivide pipelines. Could you run feeder lines to various locations in the State?

FRANK GUERIN

Insofar as the 90 pound rail is concerned, Southern Pacific has not used this weight rail on their main lines for probably 20 years. As a matter of fact, it has been taken out of our main lines and most of it re-used in secondary sidings or for industrial development spurs. I would say that for the most part, the main line networks of Southern Pacific and the other major Western railroads, such as the Santa Fe and UP, are now comprised of 119 to 136 pound rail. Only 136 pound continuous welded rail,

which is very efficient and long lasting, is being used for all new trackage being laid at this time. Southern Pacific, at last figure, had close to 6,000 miles of welded rail in place of its system of 13,000 miles extending from Portland, Oregon to St. Louis.

I am not acquainted with the study you have, but when you say Western railroads, you are taking in quite a few others and I cannot speak for them. It is my considered judgement, however, that the major Western lines I have mentioned, i.e., Santa Fe, UP and ourselves, have a very good, modern rail system.

ORSON ANDERSON

John Lynch, would you like to respond to the second question?

JOHN LYNCH

I don't have any difficulty with what the gentleman says. 17 million - let me start it this way. I saw a map on the wall and it showed where the coal was. The concept, that we believe in, is that you do have to have a concentration of coal source. Whether it be Utah or Wyoming, that remains to be seen. It depends on what the contracts are.

As far as 17 million tons of coal, according to the numbers I've heard this morning, there is more than adequate market for a coal slurry line, if 17 million tons is the key number.

Can you distribute the coal once it gets to California? The answer is yes. The concept that we have advanced in the Mississippi Basin is a line that essentially is the main line to Central Arkansas near White Bluff, and then the line would bifurcate and head south to Baton Rouge and would go east to power plant sites south of Memphis. That is our concept. You could bifurcate if you will, you can drop off en route if you wish.

SESSION V

**SPECIAL PANEL SESSION
VIEWPOINT OF CALIFORNIA'S NEIGHBORING STATES**

**SESSION V: SPECIAL PANEL SESSION
VIEWPOINT OF CALIFORNIA'S
NEIGHBORING STATES**

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INTRODUCTION

BY

**JON VEIGEL
STATE OF CALIFORNIA
ENERGY RESOURCES CONSERVATION
AND
DEVELOPMENT COMMISSION**

**REPRODUCIBILITY OF THE
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Your program lists Wilson Clark of the Governor's Office in California as chairing this session. Those of you that know Wilson will know that I'm not Wilson Clark, nor am I his clone. I am in this reincarnation anyway Jon Veigel. I work with the Energy Commission in alternative energy areas.

We are here today to talk about the viewpoints of neighboring states. The decision to title this session "viewpoints" is perfectly appropriate. In fact each session could well have been named that. We've heard the viewpoints of the State of California, the Federal Government, various utilities, different industries, the Sierra Club, etc. Obviously, the viewpoint from each of these perspectives is different. I believe that all of us often operate from an implicit position that since solutions to problems in our own area of expertise are somehow more complex than our view of solutions in the other areas, it is almost the duty of the other actors who make decisions to recognize this and consequently be the most accommodating in their solutions. Both by solving their problems without creating any for us, and simultaneously gratefully solving the new problems that our solutions have created for them.

We see this even in this conference in the continuation of the conventional wisdom that if only we answer the economic questions, the

technological questions, and to a lesser extent the microscopic environmental concerns, then development can proceed.

Generally speaking, although this conference has been the exception to the rule, energy statistics are used to justify one position or another and my view of statistics is that they are often used as a drunk uses a lamppost--for support rather than for illumination.

It seems that in the inevitable nature of things that states are always the last and the least considered, yet they also are inevitably in essential control of first, whether or not a particular energy development will occur, and then, if the answer is yes, controlling the detailed questioning of how and when such development will occur.

The dimensions of the polarization associated with questions of state involvement can be illustrated by noting that one extreme is the position that states rights control to the point that regardless of national context all development can be totally denied. At the other extreme is the view that state circumstances are irrelevant when national energy policies are formulated. Both extremes are untenable in any realistic view. Though no state wants to become just the energy province of the rest of the nation with the attendant detrimental consequences as historically shown by the current problems of West Virginia and Oklahoma, neither do any states accept the accusation too easily made that they are antidevelopment. Obviously we need to search for the satisfactory rather than the optimal solution; solutions will allow a state to meet both its national responsibilities and its responsibilities to its own citizens.

We are going to hear today from a variety of states that are important to California. You may hear similar comments from the different states. I have asked them to do so where appropriate since it will more emphatically underline their common problems. The structure I would like to operate from today, again given our shortened time here, is to ask each of the panel members to talk for five or 8 minutes up here. At the conclusion of all of their initial comments to ask for comments from the panel on each other's presentation, to open it up for questions from the floor, and finally to reserve enough time so that the panelists can make individual summing comments if they so choose before we end today. Rather than having to establish some priority order for calling the states I will just call them in the order that they are listed in your program.

COAL TRANSPORTATION:

THE VIEW FROM COLORADO

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Martin Robbins

Director

Colorado Energy Research Institute

For those of you who are not familiar with the Colorado coal situation, let me give you a very fast review of what it is. Colorado is a coal rich state, it has resources of approximately 230 billion tons which represents 10% of the nation's total. Most of this can be mined only on an underground basis, although the present mining is split almost equally between surface and ground mining. Present production runs about 12 million tons a year and estimates within the next 2 or 3 years are that it might go to 30 or 34 million tons a year. As a supplier to California, we are probably a marginal supplier at best; most of the Colorado coal will probably move east and south to Texas to Missouri and other states east of us.

However, the situation in relationship to us and California is one that we view as a Rocky Mountain state with a set of very, very severe problems, concerning the rate of development and the kind of development that will occur in Colorado and the concern that is expressed both by the Legislature and the Governor of the State. They have both made it abundantly clear that under no circumstances will they allow Colorado to become an energy colony of the rest of the nation. The kinds of words that have been used both around this meeting and that we hear very regularly are those that are absolutely complete colonialism. The belief we now have is that states rights did not die with Orville Faubus. There are new sets of coalitions occurring in the State of Colorado that are directly addressing these issues of how we can determine our own futures, rather than these futures being determined by people in Houston, or in Washington or in Sacramento. This is a much more serious problem than I think many of the people around at this meeting realize. The nature of energy production in a western state like Colorado is such that the power base is highly distributed, it is not centralized, the Governor does not have that much control nor does the Legislature. It goes down to a very, very low level-county commissioners, town councils. Energy development can be scotched anywhere along the line and the attitude that is increasingly becoming apparent here is us and them. It is primarily directed against Washington because so much of the land in Colorado is owned by the Federal Government; the Bureau of Land Management controls much of the coal leasing in the State and what has occurred is that for the first time BLM now has signed a letter of intent

that all new leases for coal must be signed by the Governor as well as by BLM. This is a tremendous amount of power that has been put back into the hands of the State and this means that there are questions that are being raised in Colorado regarding what kind of development we want, where it will occur and at what rate it will occur.

Underlying all of this is an issue of water. If Mr. Lynch is in the audience I have to say that I was quite surprised that he talked about a slurry coal pipeline without ever once mentioning the word water, which is the only major policy issue as far as the people of Colorado are concerned. There were several pipelines that have been proposed in Colorado. The Governor has said he will not allow water to be mined in the State and moved outside. What power the Governor has is hard to determine, but there are all kinds of nit picking little ways that a state can enter in to prevent development occurring, as people here well know.

I've tried to give you a pervasive attitude that is growing. It is bringing conservatives and liberals into the same camp, it is bringing ranchers and the Sierra Club together and it is not an anti-development attitude. It is a very strong pro-development legislature and yet they're questioning what they consider to be the arrogance of Washington and everybody is running against Washington, which means that they are running against coal development, if it occurs in a certain way. People have got to see what Craig, Colorado looks like to understand the meaning of a Boom Town, of what economic development means out there. I use the same thing with Wyoming, you have to see Gillette, Wyoming to understand what it is. There is no water out there, there are towns that exist out in the middle of a highly semiarid area, with their own community, their own infrastructures which people are very concerned about us having to pay the cost, for benefits that will be sustained elsewhere; that includes California.

Last night's program was perfectly clear. The speaker suggested forming an organization of coal producing states. He literally was seeing this as an economic war between the haves and the have nots. He was stating the grounds upon it and I'm afraid that is exactly what it will come to. It is a fear because that is not the way answers are arrived at.

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COAL USE IN CALIFORNIA

VIEW FROM UTAH

Reed Searle

Director
Utah Energy Conservation and
Development Council

This morning, as I entered the hallway, somebody grabbed me by the shoulder and said, "Hey, do you know what the Polish energy policy is?" I prepared myself for a good Pollock joke and I said, "No, what is it." He said, "It is the same as ours." With regard to Utah policy for coal to California, that is about where we stand - at a rather unsophisticated policy statement. So my comments are not official State policy, but are sort of an assessment of the general feeling of the Governor, the Legislature, the Energy Office and the State of Utah. Of course, I think Governor Brown told you that the State of Utah had joined California's Energy Commission in doing some joint studies to help the State of Utah develop a more sophisticated policy with regard to the exportation of electricity to California and the exportation of coal to California. At the same time Utah will provide California with some ability to utilize coal from California or to consume Utah coal in California.

Utah is ranked 14th in the United States in total estimated undeveloped coal reserves at about 23 billion tons of coal. The vast majority of that is underground deep coal mine coal. 91% of Utah's coal reserves are located in three fields. The Kaiparowitz Plateau coal field in the southern part of the state, the Wasatch Plateau and the field in the Carbon Emery area, located in the central part of the State. The Kaiparowitz Coal field, which I think is the largest untapped coal reserve in probably the United States, and perhaps in the world, unless there are some fields in Alaska that may yet prove to be larger. It is located quite close to the State of California. It is in the southwestern part of the State and to date it has not been tapped. No production has occurred, or is likely to occur in the near future on that field and as has been pointed out to you today, there will be substantial commitments of coal from the plateau before it can be economically mined because of the need for some very expensive transportation systems out of that area. About half of the coal produced in the State of Utah is consumed in the State, the other half is exported. We export coal to 17 states in the United States, all the way from Florida to Washington and we export a small amount of coal to Japan and a couple of other foreign nations because of its special quality.

California uses Utah coal now to fuel some steel mills and some other industrial users including some cement factories.

As a result of the best available control technology requirement, however, the demand for low BTU Utah coal in the eastern part of the state has been substantially diminished. Utah now perceives its major potential export market to be Nevada and California. Most of Utah coal is owned by the Federal Government, with the ownership percentage ranging from a low of 59% outfield in the southwestern part of the State to 91% of the Kaiparowitz field in the same general area.

There are presently 19⁰ Federal coal leases in Utah and only about 20 of those are operating. I'm aware of about 38 preference lease applications for additional leasing in the State of Utah, lands which contain about 1.4 billion tons of recoverable coal reserves. All of these applications have been on file for the last 9 years and no action has been taken by the Federal Government. There have been court battles, a recent decision, Hughes versus NRDC, allowed the processing of a few of those, but did not allow for the approval of those applications. Coal leasing in the State of Utah has been at a dead standstill for the past 7 years and even 2 years prior to that there was very little coal leasing that occurred.

The Intermountain Project, which you have heard is being proposed for the central western portion of the state, will produce 3000 megawatts of electricity upwards of 75%, more likely 65%, of that power will come to the State of California. After that the State of Utah will not consider constructing any more power plants in the state for exportation of power to California until the study, I have been informed, has been completed and a policy established about whether or not we will continue to export electricity to California. The issue with regard to shipping to California is shipping Utah water by wire to California. Somebody asked me to comment on that. We don't have very much water in Utah. We have a very adversary position with regard to California and Colorado River water. Coal slurry pipelines will not be built in the State of Utah to California unless there is a guarantee that the water will be returned to the State of Utah or that some type of an exchange agreement will happen. So far we haven't figured out a way to do either one of those, unless

you actually build two pipelines side by side and you literally ship the water back on the same right of way.

Current coal reserves now available from Utah coal fields are comprised of less than 2 hundred million tons classified as desirable. That means it is low sulphur coal, it is high heat value located in the accessible areas and formations. About 4 hundred million tons are also available but we have classified those as high sulphur coal, difficult, expensive access, location in thin or multiple seams or in fractured zone formations.

Without considering plans of Utah power and light for other than those planned now by the IPP sponsors and by Utah Power and Light, in that same region for an additional 2000 or 3000 megawatts, there is not now in the State of Utah currently available coal supplies for long term contracts to meet the demands in Utah. If the State of Utah is to provide or is to support exportation of coal to California, it seems to be imperative that lands in the state that do contain low sulphur, high BTU coal in areas that are readily accessible for transportation be made available for leasing through competitive bidding by the Department of Interior or that the Department of Interior allow lease holders in the State of Utah to exchange leases that are now in existence for non-leased areas which the state would like to see under lease.

Preliminary analyses of potential power plant sites within the state have indicated that there are sufficient areas in the state to build the power generation capacity that we expect to be required by the State through the year 2010. These potential sites, all of them are clustered in about a 15 mile wide belt from east to west of the state, from this Lindo area on the west over to the Green River and Price on the eastern part of the state; however, the present review by federal agencies of primitive areas, national monuments and areas for potential class 1D redesignation may well eliminate some of those plant construction sites. Also forthcoming clean air regulations on visibility and nitrogen oxides are likely to cause difficulty with some of the sites. A project which recently received preliminary green light from both the state agencies and the federal agencies is now in apparent trouble because some biologists have added two more fish species, the bonetailed chub and the razorback sucker to the endangered

species list and it is very likely that those endangered species may well prevent the development of the water project necessary for that power plant project.

Another fish, the Wound Fin Minnow in the Virgin River has delayed for over 2 years, a 500 megawatt plant in the southwestern corner of the State of Utah and a 1500 megawatt plant in the Las Vegas area in Nevada.

Unless these regulatory roadblocks can somehow be removed, and water projects funded, California cannot count on receiving any more electricity from the State of Utah other than what it will receive from the Intermountain Power Project. Utah has joined with California in this "assessment" of power plant capacity in Utah and in California an assessment of coal availability in Utah for California. As part of that study, future coal demands in both Utah and California will attempt to be assessed and a determination made about whether or not Utah can or will export coal, or possibly even electricity, to California.

In summary, lack of federal coal leasing programs or coal leasing exchange programs, the Endangered Species Act, BLM wilderness review, problems in developing a short water supply, all impede substantially Utah's ability to develop its own resources and in particular its ability to share those resources with other states.

Utah won't take an isolationist position if it can meet its own requirements. We find ourselves, however, with regard to water and coal and power plant development, in what we call a federal straightjacket. We have found in Utah that industry has been quite willing to work with us to meet the demands of the State and the requirements of the State. In fact, in some instances, they have gone beyond what has been required of them. We expect that industry, utility industries especially, will do a good job in protecting the environment and financing without being required to, financing the infrastructure and taking care of the impacts they cause. Finally Utah, as indicated before, will not build additional power plants for California if such plants can be built within the State of California and meet the same regulations. Nor will Utah slurry coal to California unless the policy of water exchange is implemented.

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COAL USE FOR CALIFORNIA

VIEWPOINT FROM ARIZONA

Tom Lynch

Arizona Energy Programs Office

My function here today is to contribute some Arizona viewpoints, some of the topics discussed here at the conference and perhaps the best way to begin that is to point out some very important characteristics that Arizona shares with California. We have some Democrats and some Republicans. We have some growth advocates, some environmentalists, some technologists, some futurists. We even have a few who would like to repeal most of what has occurred in the last half of the 20th century.

We also are seeking a balanced solution to this pressing problem of energy supply and demand, and we are doing it as are the other states in a very complicated economic and social environment. Some of the positive aspects that Arizona can bring to solution of energy problems are substantial coal deposits in the Four Corners area, a good potential for geothermal energy, some recently improving prospects for uranium development, a limited potential for increased hydroelectric generation. However, this is shared with a number of upper and lower Colorado River Basin states, so that its role remains to be seen. Last but not least, there is an abundant solar energy potential, here again that is off in the future. On a less encouraging note we are also painfully aware of some of the pressing limitations of our future ability to provide the energy that our dynamic growing economy will demand. For the past decade Arizona has been at or near the national top in growth rates, so even if we do succeed in reducing per capita energy demands, more energy will be required to meet our rapidly expanding population and our growing economic base. Throughout the history of Arizona, water has been an urgent concern. Not too many years ago these conflicting claims for water were settled with a six gun. Fortunately, we now have developed better methods of settling these contentions, but the fact remains that they still are occurring. We are now mining several million acre-feet of water each year that takes centuries to replace for our existing uses. Any additional energy production will require tradeoffs between now existing water uses and those of energy production. The cost of water is increasing at an alarming rate and it may make uneconomical some of the current uses of water; perhaps therein lies part of the solution.

To complete the summary of major energy concerns you have to add one more that we share with California. That is the air quality. We in Arizona have a priceless heritage of clean air and

open space, that is a basis not only for our unique Arizona lifestyle, but also one of the second in fact the second largest segment of our economic activity, that of tourism. We are very much concerned that this situation, which is important both to our social and economic lifestyle is preserved.

In summary, I believe that Arizona brings essentially the same concerns to the solution of energy problems that our neighbors have. We recognize on both a regional and national basis we're highly interdependent and I think Arizona will do its best to navigate, help navigate, this leaky boat that we all find ourselves riding.

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VIEWPOINT OF CALIFORNIA'S NEIGHBORING STATES

Nick Franklin

Secretary, Energy and Minerals Department
State of New Mexico

It is a pleasure to be here today and to have the opportunity to share with those of you here from California as well as from neighboring states some of New Mexico's views on increased coal use for California.

You may not be aware of this but there are those around the country and particularly the eastern seaboard who are less versed in geography and actually think New Mexico is somewhere south of the border. This attitude has even been verified by letters from mysterious federal agencies asking whether New Mexico is exporting this or that novelty to the United States. I know of a woman from Santa Fe who travelled all over Europe cashing checks with no difficulty. When she returned to the U.S. and was passing through New York, she went to a bank near Wall Street and tried to get some money for shopping, but the teller took one look at her New Mexico check and gave it back, saying: "I'm not allowed to accept foreign currency."

This all may seem far-fetched and I must say New Mexico has a booming tourist business whether the tourists think they are in or out of the country. Unfortunately, however, it is probably close to the truth that many, especially in heavily populated, energy intensive areas of the country, have little idea of what role New Mexico plays in providing their sources of energy. New Mexico, in fact, is a significant producer of all energy forms. The state ranks 11th nationally in its total coal reserves and is the 14th largest producer of coal. Perhaps more significantly, New Mexico is the nation's first largest exporter of uranium, second largest exporter of electricity, and fourth largest exporter of natural gas.

After the experience of flying into Los Angeles and recalling a trip to the east coast last month, I have been struck by the dichotomy of energy consumption compared to New Mexico's. As I fly over acres of swimming pools and drive by miles of neon signs, I am made doubly aware that New Mexico and other Rocky Mountain states are about to see tremendous outside pressure to develop their resources, and in some cases deplete them in a relatively short period of time, while these heavily populated areas seem to be flaunting energy as though there is an inexhaustible supply. I am also struck by the irony of California experiencing

an oil glut and the fact that ships are going out of their way to come to California to pay a cheaper price for oil.

Perhaps I am being unfair to those making a conscious effort to conserve energy and use energy efficiently. I am aware that even though California consumes more energy than any other western state, the consumption per capita is low. Of course, you also have a more cooperative climate for energy use than most states.

The fact remains that energy intensive sections of the country obviously expect to maintain present or higher levels of energy usage while at the same time hoping to avoid detrimental effects. Instead, the detrimental effects are being visited upon the energy producing states of the Rocky Mountain region. And while this takes place at an alarming pace, urban areas of the coasts that have a lot of political clout by sheer numbers continue to be the source of greatest demand while putting moratoriums on environmentally threatening fuel sources such as coal and nuclear energy. Because, however, of the extent of this pressing demand from these areas and the lack of meaningful conservation, the only immediate options to meet these levels of demand are the coal or nuclear alternatives. New Mexico, it must be remembered, hasn't set that pace and level of demand. And it is beginning to look as though New Mexico will not have much to say about which option is chosen by the large users even though New Mexico will be a major supplier of the fuel sources.

For a period of 25 years, California was spoiled by relatively inexpensive and efficient natural gas from New Mexico as well as from other states. California has been responding to some of its air quality problems which have been caused in great part by too many cars that have been and continue to be powered by inexpensive fuel. One response has been the use of clean natural gas imported from New Mexico and other states.

The gas that New Mexico furnished California from 1950 to 1973 would have averaged less than 13 cents per Mcf at the wellhead. Converting that to its oil equivalent, that would be somewhere around 71 cents per barrel of oil. Oil itself was \$4.11 per barrel in 1973.

It doesn't help now to find out that natural gas could have been used much more efficiently if a realistic cost had been attached. But we calculate in New Mexico that the lack of a fair price has cost the state hundreds of millions of dollars in lost severance taxes let alone other revenues. And it does not help to reflect that these revenues could have gone to raise New Mexico above its once 49th and now 46th in the nation in per capita income status. California, which I believe ranks eighth in per capita income, has paid even less than New Mexicans for New Mexico's natural gas.

That unfair relationship continues to exist in many of New Mexico's exported resources. I am concerned that history doesn't repeat itself in carrying on the natural gas experience to extensive coal production. Already there are hints of this condition with Utah expected to offer a \$5 equivalent in coal to what would be a \$14 barrel of oil.

Obviously New Mexico recognizes an obligation to share its abundant resources. We are north of the border and have no intention of hoarding resources or of taking unfair economic advantage of this country that could in the near future be brought to its knees by the vagaries of supply and demand. In fact, New Mexico in the past has gone overboard in supplying energy needs at the expense of great socioeconomic impacts to communities undergoing boom and bust cycles, at the expense of environmental degradation from rapid resource development, and at the expense of water quality and depletion of tremendous quantities of our scarce water resource.

New Mexico furnishes coal to California primarily through coal-generated electricity. California imported about 70 percent of the exportable electrical energy in the West in 1974. Because natural gas has been used up so rapidly, California will represent a much larger electrical energy market in the future than was the case in 1974. Much of the coal-fired generation is devoted to supplying some of the California market.

New Mexico uses about 7 billion kW-hr of electricity while California consumes 133 billion kW-hr. But California imports 20.3 percent of its electrical energy and exports none. New Mexico, on the other hand, imports none and exports 59.6 percent.

I have what I think is a fairly good portrait of production and consumption in a graph showing the position of Western States in 1974 (Fig. 1). Unfortunately, figures for 1974 are the most current data I have available though I know the picture now is even more dramatic with California expecting to seek more electricity from coal-fired plants. Figure 2 shows a comparison between the two states of production and consumption. The high tower to the right is California, showing production at about half of consumption. New Mexico's consumption, however, is about one third of its production.

In a graph of net energy balances of Western States in 1974 (Fig. 3), we can see that New Mexico shows a surplus while California shows a substantial deficit. Of the 13 Western States, only Alaska, Montana, Wyoming, and New Mexico show a surplus. These, of course, are the states that

are facing the most pressure for rapid development of their energy resources. Though these are 1974 figures, our information indicates that this imbalance has become even more dramatic.

The increased development of coal that is planned will clearly have a great impact on coal producing states. Court testimony, for example, has revealed that power plants in New Mexico, from which most of the power is exported, cause an estimated \$12 million of environmental damage a year. And yet, California is receiving clean energy in the form of transmitted electricity from this power generation. Testimony also revealed evidence that socioeconomic problems caused by the plants may cost as much as \$27 million to remedy. And if these utilities were to generate the same amount of electricity at plants outside of New Mexico, it would cost them an additional \$124,000,000 annually.

We all know that a price can not be put on air and water quality. And water is a precious resource in New Mexico, a condition Californians can understand. Such scarcity makes coal slurry pipelines a rather doubtful option. Nevertheless, New Mexicans have sought a means of fairly distributing the burdens of production and exportation, and to assist in ameliorating the environmental and socioeconomic impacts.

In the specific area of electrical generation, New Mexico enacted an electrical energy tax act that provides for an approximate 2 percent generation tax. California utilities have responded by strongly contesting this tax in court. Even though New Mexico's State Supreme Court upheld the tax, opponents are expected to appeal it to the U.S. Supreme Court. Given the past history of inexpensive energy supplied to California by New Mexico with the adverse socioeconomic impact going to New Mexico, and given the fact that New Mexicans traditionally have paid more for their own resources than Californians have paid for New Mexico's energy resources, the resistance to this tax leaves us somewhat doubtful of California's intention to share in the burden of meeting the nation's necessary energy needs.

In fact, California's response to the nuclear and coal options has been to let other states take the burden. California has a moratorium on nuclear power plants until the issue of waste disposal is resolved. Once again, New Mexico is expected to pick up the burden through a proposed nuclear waste isolation pilot plant, even though New Mexico receives no energy itself from nuclear power generation.

A map of scheduled coal-fired plant locations (Fig. 4) as of June 30, 1976, showed all the proposals for these plants to be in the Rocky Mountain States and none scheduled for California. A list of coal-fired electrical generation plants scheduled or under construction in the 11 most-Western States showed one plant scheduled for California out of 58 plants even though it is clear California will be receiving much of the increased energy in future years.

I think, considering the historic cost of resource distribution, the production-consumption balances and the existing patterns of who supplies

the resources but receives the brunt of adverse effects, that California had better take a closer look at the options available. I hope that the New Mexico viewpoint will have an impact on your decisions about increased coal use for California.

And if you want coal as an option, we have supplies of coal, but California will have to accept its responsibility to share the burden by building plants in California and/or to share the costs of adverse effects from plants outside of California.

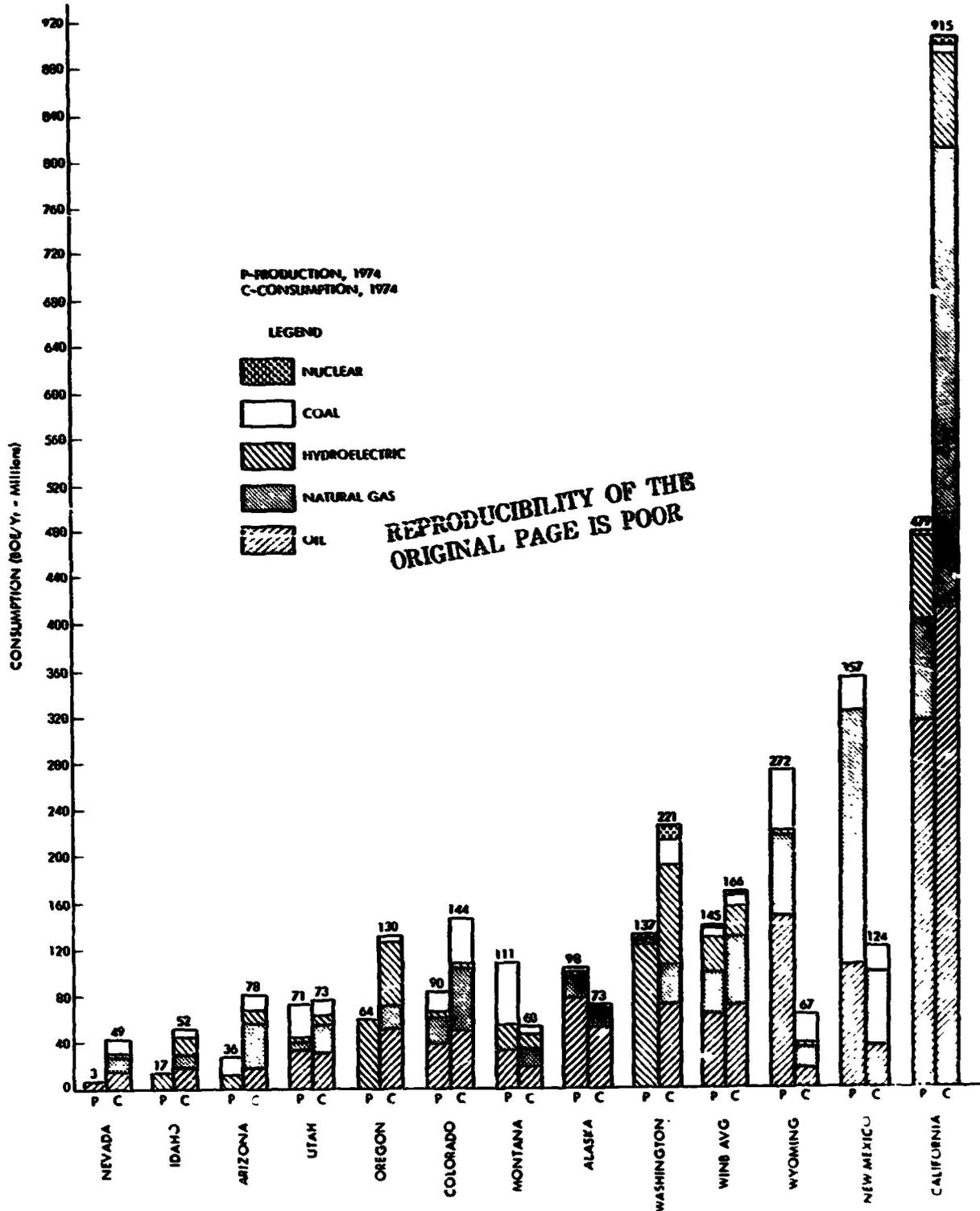


Figure 1. Energy forms involved in production and consumption in Western States - 1974

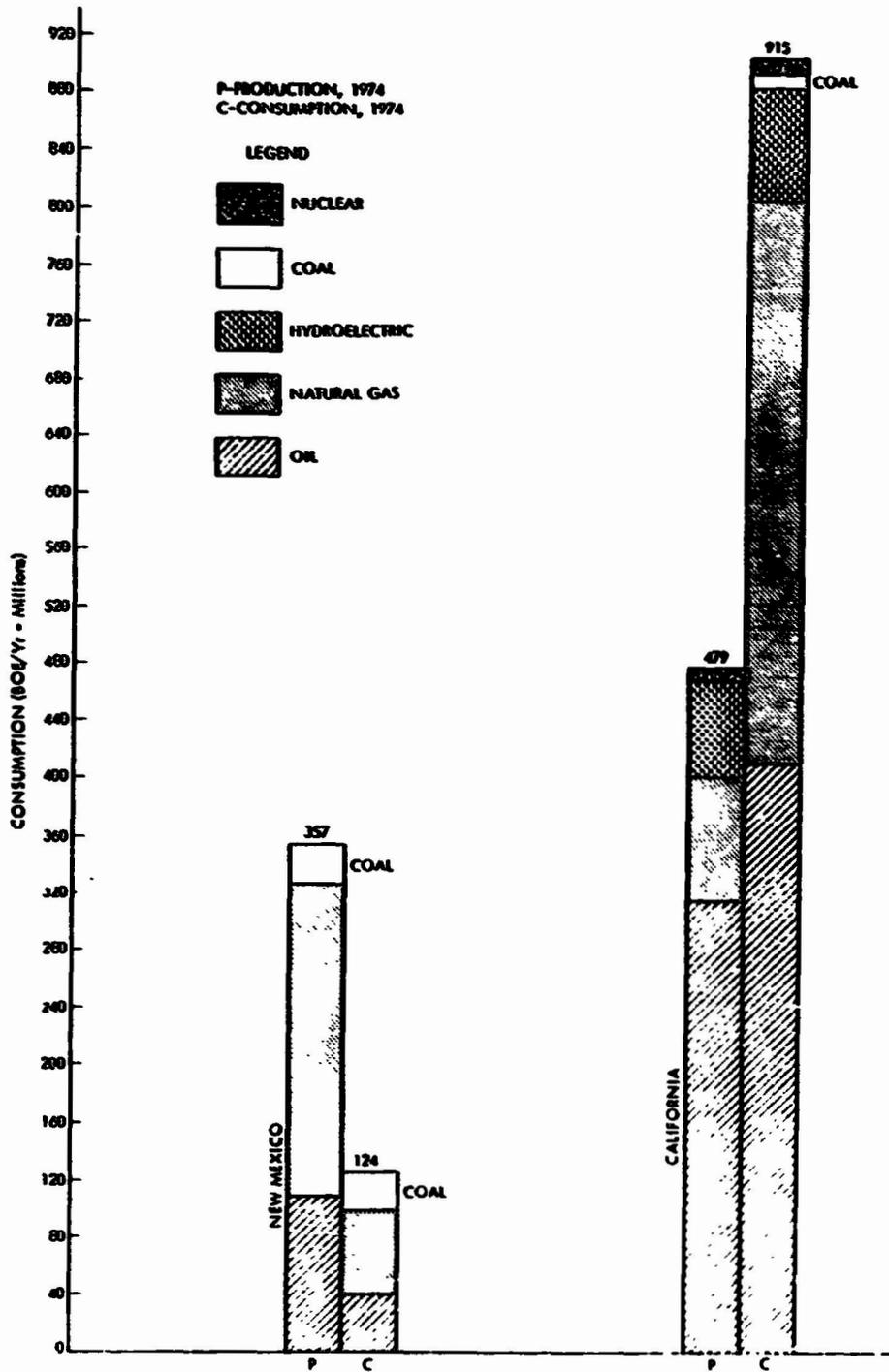


Figure 2. Energy forms involved in production and consumption in New Mexico and California - 1974

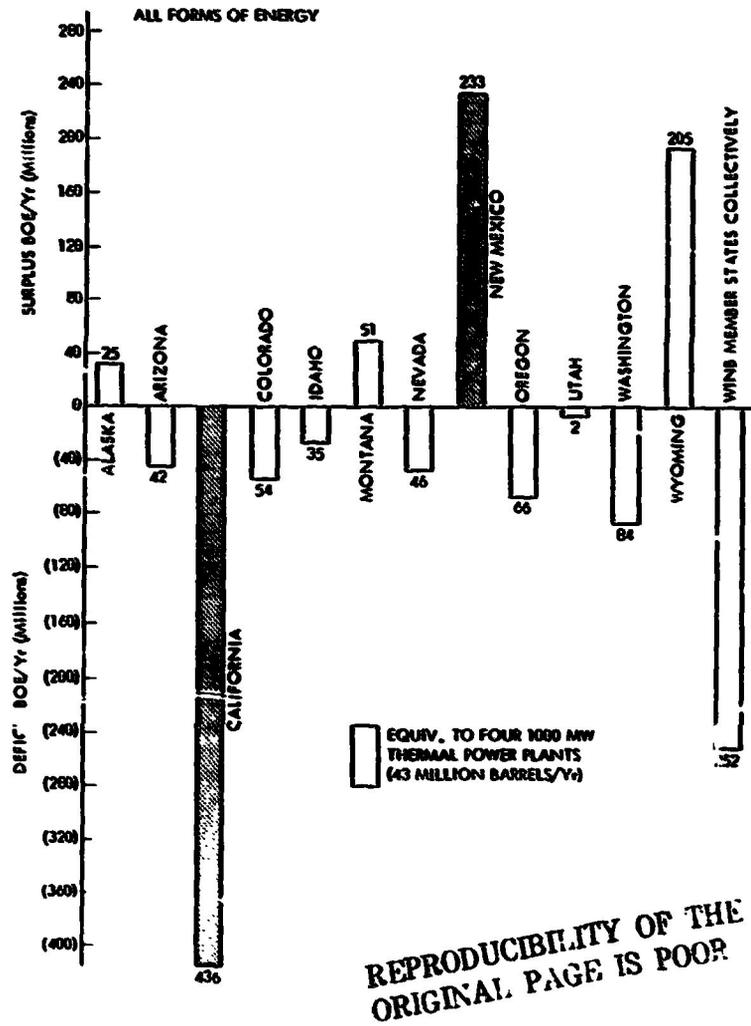


Figure 3. Net energy balances of Western States - 1974

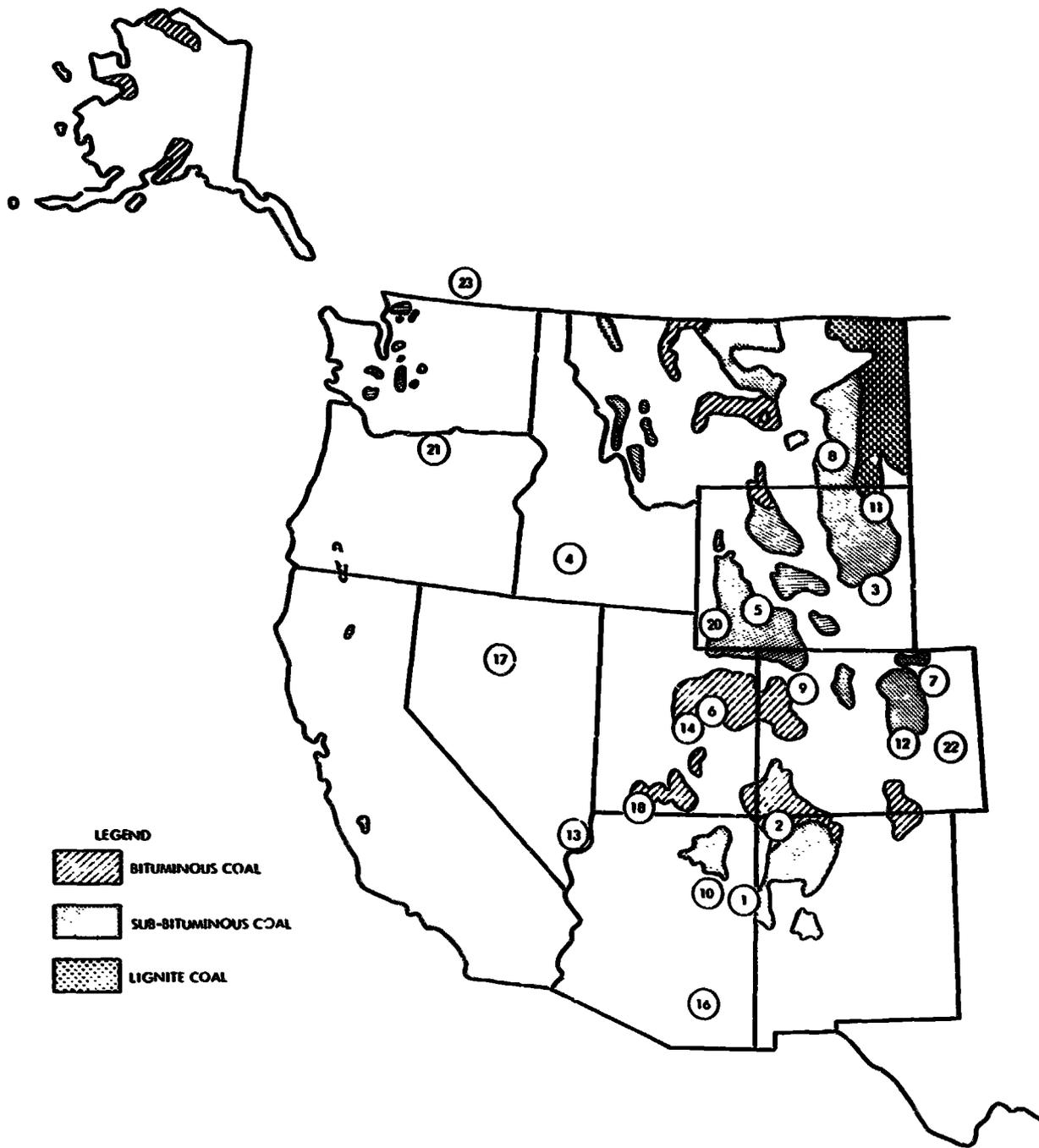


Figure 4. Scheduled coal-fired plant locations in WINB member states (as of June 30, 1976)
 (adopted from Western Systems Coordinating Council April 1976
 listing of scheduled thermal generation facilities)

STATE OF WYOMING POSITION REGARDING INCREASING
COAL USE IN CALIFORNIA

Lynn Dickey

State Energy Conservation Office
Cheyenne, Wyoming

I am pleased to have this opportunity to express Wyoming's concerns regarding an increase in the use of coal in California, particularly this early in California's decision-making process. The State of Wyoming will, in all likelihood, feel the effects of any decision to significantly increase the amount of coal used by California. Wyoming is one of the nearest coal-producing states to California, and would surely be considered, as it was in the recent UCLA study on coal for the Los Angeles area, as a potential supplier.

Demands on Wyoming coal are increasing at a very rapid rate. Within the last five years, coal production in our state more than quadrupled (from 10 million tons in 1971 to 44 million last year) and we receive two to five applications for large new coal mines and major mine expansions every month. Our production of uranium is growing at an even more rapid pace (now over 3 million tons per year), and we continue to be a major producer of oil and gas (134 million barrels and 330 billion cubic feet), electricity (3,500 MW per year), trona (9 million tons per year), iron ore, and bentonite.

Certainly, economic growth is beneficial to any state, but there is such a thing as too much too fast, and that's what's happening in most of Wyoming. The growth we're experiencing is placing tremendous strain on the state's communities, agricultural economy, land, water, air and wildlife resources, and way of life.

Wyoming has historically been a rural state, with an economy based on farming and ranching, tourism, and oil and gas production. We have had small, uncrowded communities, with very little crime, neighbors who know each other, adequate services, and a very easy-going way of life. In 1970, we had a population of 332,000. Our two largest cities were both at around 40,000. Most of the population centers in the state had populations of between two and seven thousand.

According to the most recent census figures, Wyoming now has the most rapid growth of any state in the Union. Within the past five years, a number of towns in the mineral-producing areas of the state have more than doubled in population and the growth is not slowing down. That type and rate of growth exceeds any community's ability to adequately meet its residents' needs, and utterly alters the character of any rural community. There has been a tremendous increase in the amount of crime, drug and alcohol abuse, divorce and child abuse in these communities.

There is woefully inadequate housing, water and sewer systems, fire and police protection, and an above-average inflation rate. And there is substantial animosity between the more conservative, settled old timers and the highly-paid, city-oriented newcomers.

Rapid growth in mineral development and population also adversely affects the agricultural economy. It becomes more and more difficult to maintain an already marginal ranching and farming operation as the number of people unfamiliar with such operations increases and moves closer. More gates are opened and not reclosed, more fences are damaged, more wildlife and livestock are poached, more domestic dog packs destroy property and animals. And the inflation rate in towns hits particularly hard those whose income doesn't rise concomitantly, primarily agricultural people and the elderly. In addition, agriculture competes with the much more well-heeled mineral industry for limited land and water resources. Large power plants and proposed coal gasification plants use very large quantities of water, which have to come from somewhere. And Wyoming is a semi-arid state, with very little available water, particularly in dry years. Every major stream in the state already has more claims on its use than it has water. It follows that any large new demand for water will have to take that water from the use to which it is now made or committed. Municipalities have top priority on Wyoming water, and we are legally bound to our water commitments to downstream states. So, additional water for the mineral industry will continue to remove water from agricultural and in-stream uses.

Wyoming's clean air and water also, of course, are deteriorating with the increase in mines, power plants and other industrial development, due to depletion and to increased discharges and emissions. So our state, as we've known it, is changing, as all things must. But, as Wyoming people become more aware of what too rapid growth will do to our state, we are placing more and more curbs and conditions on the type and speed of growth we will accept. Laws to protect our communities and our environment are being passed and strengthened each time the legislature meets.

The people in Wyoming realize that we have a responsibility to help meet the nation's legitimate energy needs. But we also realize that there is tremendous waste of energy in the areas that want our coal and uranium, and that includes California. And we continue to have a very large tourist trade every summer, much of which,

I might add, comes from California. People don't come then to look at our coal, so we surely have to consider our wide open spaces, our clean air and water, our abundant fish and wildlife, and our rural way of life to be important resources to the nation as well. And the extent to which mineral development increases, is the extent to which these less quantifiable but at least equally important resources are depleted.

So, in an admittedly round-about-way, this brings us to the subject of California, which, all things considered, should probably increase its use of coal, in the short term. But as the need to conserve fossil fuels and the need to minimize further environmental degradation increase, states like California have an additional and more important responsibility which stems from having a very large population, and comparatively little in the way of fossil fuel resources. That responsibility is to achieve the most ambitious possible goals in conservation of energy and use of nondepletable energy sources. Failure to do so is bound to cause serious, irreparable and unnecessary damage to states such as Wyoming which have abundant fossil fuel resources.

California is surely doing as much as any other state in the Union to conserve energy and to increase the use of renewable sources of energy. In any major article on what's happening nation-wide in those areas, California is always mentioned. Cities such as Davis are setting the pace for community conservation efforts all over the country. California's building standards and solar income tax credit are not surpassed by any other state. And the state has shown a willingness to put hundreds of millions of tax dollars into conservation and renewable resources.

So it is not my intention to intimate that California is lagging behind in these areas. And I have, I'm sure, an understandable reluctance to appear to be telling Californians how they should be running their state.

But, since Wyoming stands to be directly affected by California's decisions regarding increased coal use, I feel no hesitation to say what would be in our state's best interests as far as California's decision-making process is concerned. Two things:

First, in every instance where a move to coal is being considered, all possible conservation and renewable resource alternatives should be thoroughly analyzed before any decision is made. I'm sure there are differing views on the recently-released Department of Energy study on California's potential for virtual energy independence using existing "soft" tech-

nologies. But the study should at least point out that there are alternatives worth considering whenever an increase in the use of any fossil fuel is being looked at.

Second, to the extent that coal use is to be increased in California, it will surely be easier on the coal-producing states if this state will bear the burden of converting as much as possible of the coal to gas or electricity here. There is significant damage being caused by increased mining in our state due to rapid population increase, water depletion, air and water quality degradation, poor reclamation potential, and social and economic disruption. And there is significant damage being caused by coal transportation. Unit trains disrupt our communities and ranching operations, start very damaging range fires, impede access to emergency facilities in rural areas, and disrupt wildlife movement patterns; and coal slurry pipelines threaten to further deplete our scarce water supply. But large conversion facilities cause substantially more pollution and population increase. They use much more water than mining and transportation do, and transmission lines cause disruption to farm land. That's every bit as serious as that caused by trains to ranch land. And, at this point, it is the large increase in both mines and conversion plants along with the attendant growth in other business and industry that threaten to completely overwhelm our state.

Those are basically our positions and suggestions regarding increased coal use in California. Again, I appreciate the opportunity to present them to you.

MONTANA COAL
VIEWPOINT OF A NEIGHBORING WESTERN STATE

Mike Stephen

Montana Energy Office
Helena, Montana

ABSTRACT

The state of Montana has vast reserves of low-sulfur subbituminous and lignite coal. These deposits are located in the rural portions of southeastern Montana. The development of this area has a potential for expensive social impacts, air and water pollution, transportation problems, and disruption of wildlife and their habitat. Options include an orderly planned development, providing for the social concerns, further investigation on groundwater conditions, and reclamation of the land in disturbed areas.

1. INTRODUCTION

Although Montana has considerable coal deposits, most of the reserves consist of subbituminous and lignite coals. As more current studies become available, total reserves and strip-pable reserve estimates continue to increase.

Recent reserve* estimates show about 292-billion tons of coal and lignite in Montana (177-billion tons subbituminous, 2.3-billion tons bituminous and 112-billion tons lignite). Montana Bureau of Mines and Geology estimate for strip-pable subbituminous and lignite exceed 50 billion tons. One four-county area alone (Big Horn, Custer, Powder River, Rosebud) contains an estimated 32-billion tons of strip-pable reserves. Coal seams vary from 11 to 72 feet.

II. COAL CHARACTERISTICS

Most eastern Montana coal deposits are relatively low in sulfur (less than one percent) and have moderate to low ash contents. Heat contents vary from 5,830 BTUs for lignite to 9,652 BTUs for subbituminous.

*Includes bituminous beds greater than 14 inches thick, lignite and subbituminous beds greater than 30 inches thick.

Trace metal contents of any given coal seam are low and do show great variation over short distances both lateral and vertical. Total sulfur content of lignite is low, averaging 0.6 percent. Eight trace elements (copper, lead, zinc, arsenic, cadmium, mercury, antimony and selenium) are associated with pyritic sulfur (FeS_2) in coal.

III. COAL AND OWNERSHIP PATTERNS

Only in the earliest days of homesteading did the Federal Government convey mineral and coal rights with surface homesteads. Most Montana homestead land sits over federally-owned coal and minerals. Forty-one percent of Montana's 146,000 square miles is under public ownership. Present coal acreages under lease include 36,000 federal, 58,000 state, 334,000 private, 77,000 Indian, for a state total of 505,000 acres. Ownership varies in each locality. In the Decker-Birney area, federal agencies control 88 percent of the area's mineral estate and 26 percent of the surface. Private interest controls only 7 percent of the mineral and 69 percent of the surface. The Crow Tribe of Indians maintain coal and mineral ownership in the vast strip of land adjacent to the Crow Reservation and south of the Yellowstone River. Surface ownership is predominantly by non-Indian ranching interests. The mining activity involves removing Indian coal from beneath non-Indian ranch land. The northern Cheyenne Tribe of Indians has gained partial success in petitioning the Department of the Interior to cancel all existing leases and prospecting permits on the Northern Cheyenne Reservation. The Crow Tribe of Indians have initiated similar actions regarding leases on the Crow Reservation. Accordingly, the status of thousands of acres of Indian coal leases is uncertain.

IV. MARKETING MONTANA COAL

In 1976, a total of 2.5-million short tons of coal was used in Montana. Ninety-six percent was used by electric utilities (one third of Montana's electricity is generated by fossil fuels), one percent by retail dealers and three percent other usages. This compares to 26.4-million short tons shipped out of state. Transportation costs and the tax structures affect the economic picture for coal development. In Montana there are four

major taxes involving coal: the Net Proceeds Tax, Resource Indemnity Trust Tax, Corporate License Tax, and the Coal Severance Tax.

Net Proceeds Tax - This tax is imposed on the valuation placed on the net proceeds of the mining firm. The Class I property is taxed on a basis of 100 percent "true and full value."

Resource Indemnity Trust Account Tax - Tax on value of product extracted. The tax is imposed at the ratio of one-half percent of the gross mine-mouth value of all nonrenewable mineral resources, which includes coal.

Corporation License Tax - Tax on corporate net (6 3/4% of net income derived in Montana).

Coal Severance Tax - Imposed on all coal mined in the state. Five thousand tons of each calendar quarter's production is exempt from tax.

Table 1. Montana's Coal Severance Tax

BTU rating	\$ per ton	Percentage of Contract Sales Price
Strip mine (whichever is larger)		
Under 7,000	\$0.12 or	20%
7,001 - 8,000	0.22 or	30%
8,001 - 9,000	0.34 or	30%
Over 9,000	0.40 or	30%
Underground mine (whichever is larger)		
Under 7,000	\$0.05 or	3%
7,001 - 8,000	0.08 or	4%
8,001 - 9,000	0.10 or	4%
Over 9,000	0.12 or	5%

Coal Severance Taxes paid through 1976 amounted to \$49 million. The average mine-mouth price for Montana coal in 1976 was \$5.72 per ton compared with \$4.97 per ton in 1975.

V. MONTANA'S COAL PRODUCTION

Montana's coal production has grown from 301,000 tons in 1960 to 28.6-million tons in 1977. The 26.2 million tons produced in 1976 was an increase of 19 percent from the previous year. While the 1977 production is only up 4 percent from 1976.

The acreage required to produce this amount of coal for 1977 was 770 acres. This is the average of 35,240 tons of coal mined for each acre disturbed.

Montana coal production estimates based on existing leases, new production, and projected production are 65.0 million tons in 1985 and 70.5-million tons by 1990.

VI. AREA IMPACTS

The clustering of fuel-related projects in Montana occurs in the eastern section. Some projects may be discontinued while others may come

on-stream due to the national energy shortage, improved technologies and development of economical transportation. The influx of population into these areas of increased energy production and related activities will induce pressures on the state and local government to provide schools, roads, water and sewer systems and other public facilities and services. Fortunately, the Montana State and local tax system has been designed to collect revenues rather quickly when mining and related developments are undertaken. The most flexible of which are the coal severance tax monies allocated to the Coal Board. Unlike counties and school districts, municipalities do not have added to their property tax roles the substantial increases in taxable property which result from energy-related developments.

Surface mining also destroys the existing natural communities. Restoration of a landscape disturbed by surface mining to recreate the former conditions, is not possible. Techniques have been developed to revegetate some lands particularly in high rainfall areas. In the more arid areas of eastern Montana, revegetation can probably be accomplished with major inputs of water, fertilizer and management.

The coal producing areas of eastern Montana are also underlined by the Madison Limestone Formation which is an excellent collector and transmitter of water. Precipitation may infiltrate to only shallow depths or may pass completely through the formation to an impervious layer. The recharge/discharge relationships are not understood. A better understanding through observation wells during both "wet" and "dry" periods and monitoring the effects of current mining practices is being undertaken.

The movement of coal to points of use outside Montana is presently accomplished by rail. The present and near future capability of these railroads to meet the needs of the coal industry appears adequate. There is some question of bottlenecks on short routes and rivers or mountain barriers.

The major water source in the eastern coal region of Montana is the Yellowstone River. Current requested water reservations exceed the annual flow of the Yellowstone. Pending a one-year moratorium, additional applications have been filed. If surplus water is totally allocated through water reservations on an average or low-flow basis, then the first reservation adopted may have a firm water supply, which subsequent ones would not.

Pumping water for a slurry pipeline is another alternative. This water would come from the Madison Limestone Aquifer. The water requirements for such a pipeline would have wide ranging adverse effects on ground water levels. This in turn yields a greater concern by all for the environment while moderating the social impacts brought on by energy development.

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COAL USE FOR CALIFORNIA

Richard Eakins

Division of Economic Enterprise
State of Alaska

My purpose this morning is to provide the State of Alaska's viewpoint and policy as a potential supplier of coal to a California market.

To put our viewpoint into perspective, it is useful to outline the future direction of Alaska's economic development program.

Our goal is to provide for a rate of growth of the economy such that it will:

1. Provide sufficient creation of new jobs to employ the present Alaskan labor force and their children as they enter into the market.
2. Facilitate the diversification of the economy to minimize seasonality and cyclicity.
3. Generate an adequate revenue base so that State Government can be weaned as soon as possible from its utter dependence upon nonrenewable resource revenues.

Let's state what I believe to be some basic facts:

1. Alaska's economic growth for the long-term future will center around resource extraction development.
2. This resource extraction includes non-renewable resources; tourism is included in the above.
3. The State has tremendous potential for developing diversified sources of energy power over and above its own consumption needs. This could be sold to industry, or exported.
4. Resource extraction and direct export to outside markets will not in itself provide the economic return necessary to achieve the above basic goals of economic growth. Value-added processing will need to take place. To do this, a basic industrial base will need to be established. This industrial base will center around resource materials processing and the availability of long-term power supplies.

Conclusion:

Alaska's option for obtaining a rate of growth required to accomplish its economic goals is to develop its renewable and nonrenewable resources and energy resources and make provision for establishing a basic industrial base to add value on export materials.

One of the resources we believe to be at the near-development stage is our coal resources.

Alaska has huge coal resources -- an estimated 1,000 billion tons. Much of this coal is located in the northwest part of the State, too remote to expect near-future development.

Presently there is now in production the Usibelli mine at Healy with an annual production rate of approximately 750,000 short tons. While Alaska's coal has a high moisture content, it has a very-low sulphur content.

The greatest potential for new immediate development is the Beluga Field west of Anchorage. The field is 20 miles from tidewater access at Cook Inlet. This makes the development attractive, in that coal or its processed product can be exported by ship with minimal land transportation costs.

We are presently looking for markets for this coal in the following ways:

1. As a mine-mouth power generation source to provide power to the local area and at a capacity to attract intensive energy industries on site.
2. As an export market for lump coal or some form of slurry fuel shipped to the Pacific Coast, Pacific Northwest, Japan, or Korea.
3. Converting the coal into a liquid fuel or gas such as methanol or methacoal.
4. A use of the promising new technologies for converting coal to forms of energy.

We realize that to sell our coal, we have to be competitive in price and quality with

Alternative energy sources. We believe we are now at that stage where Alaska coal can become competitive on the market.

We have the advantage of large resource amounts, easily available, close to tidewater and relative low-cost water transportation. We recognize that Alaska has cost differentials to overcome which tend to inflate our delivery price.

However, these are being overcome rapidly and resolved with new technology. If we can deal in volume amounts, unit costs can be reduced dramatically.

We are examining other ways in which the State can help reduce costs through the provision of incentives.

As the proverbial Southern California used car dealer touts, "If you're going to buy, don't buy until you check our price."

We are serious about moving our coal to market. It is a long-term stable source of supply measured in the dozens of decades. We are also offering a special for Southern California customers. If you are interested, we are willing to talk on the possibility of shipping coal slurry in water.

REPRODUCIBILITY OF THE
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**SESSION V: SPECIAL PANEL SESSION - VIEWPOINT OF CALIFORNIA'S
NEIGHBORING STATES**

Session Cochairmen: Jon Veigel (Governor's Scientific Advisor)
Dan Schneiderman (JPL)

Panelists: Martin Robbins (Colorado)
Reed Searle (Utah)
Tom Lynch (Arizona)
Nick Franklin (New Mexico)
Lynn Dickey (Wyoming)
Michael Stevens (Montana)
Richard Eakins (Alaska)

OPEN DISCUSSION BY ATTENDEES

JON VEIGEL

Thank you Richard, I would like to give a few moments here for any additional comments any of the panel members have before we open it up to questions from the floor. Is there anybody that would like to say something that was stimulated by any of the panel members comments.

NICK FRANKLIN

I have one question that we probably didn't address enough, and it was touched on by Mike Stevens from Montana, the whole question of Indian interests. In New Mexico, 63% of our coal reserves lie on Indian land, so obviously the State doesn't have much to say about those particular interests. We work cooperatively, when we can, with the Indian tribes, especially the Navajo Nation. At breakfast this morning, we were discussing this particular issue and lamenting that perhaps at this conference or at least future conferences, Indian interests should be represented to some extent. I think those that were involved in the Westco Project are smarting from having to deal with the Indian Community, but at least in New Mexico, and I think elsewhere in the country, the native Americans are becoming very sophisticated negotiators and very wise as to what they have and what their rights are,

with regard to their mineral resources. It is a real problem that we have to deal with. This is not the 1800's when we could bowl them over. I think that was one problem that we didn't emphasize enough.

Lastly, there is an organization called WESPO, the Western Governors Policy Office. There are 10 member states and the Governors sit on the governing board of that office. That organization was somewhat organized as the result of the energy questions we have raised here today. To give you an example, I'll read you the state membership on that. Alaska, Arizona, Colorado, Nebraska, Montana, New Mexico, North Dakota, South Dakota, and Wyoming and, somehow Hawaii slipped in. Those are the states and basically the things that we are talking about are some of the exact things that we are talking about today.

JOHN VEIGEL

Are there any other panel comments?

UNIDENTIFIED ATTENDEE

If you add to that, California, Idaho, Oregon and Washington then you have the Western Interstate Energy Board, which is the energy subcommittee of WESPO.

JOHN VEIGEL

Texas is in another council, are they not?

NICK FRANKLIN

Texas is in a completely different council at least if your point is made towards the Governors Conference, yes. As it was stated last night, basically Texas' coal reserves are within the State of Texas and they have no overlapping electrical generation hookups. Most of their oil is kept there so they are generally addressed differently.

CHARLES MANN

I'm with the Energy and Environmental Analysis Inc. One of the questions which was addressed yesterday in talking about the need for new coal fired power plants in California, and which was addressed particularly by the Wyoming representative today, is establishing a credible justification for the need, either to supply power from minemouth generating plants in other states or coal fired power plants in California. As everyone is aware, one of the primary challenges to the Federal Leasing Program in the successful suit of the Sierra Club and then NRDC of a couple of years ago was that the Interior Department hadn't made an adequate case for the need for coal leasing, the amount of coal leasing or the appropriate locations for coal leasing. I wonder whether any of the panel members would like to comment on what they would consider appropriate policy making form to set reasonable targets for coal leasing. Also what is an adequate justification or planning process to say that the coal ought to be mined and is needed to satisfy California's energy needs.

MIKE STEPHENS

I don't know that this is going to answer your question, but given that we need electricity, and energy in various areas, there is also the fact that there are a lot of renewable soft technologies which could come to bear in the near future. Maybe some of the technologies are rather rough, but the question arises, do we need these large central facilities, at the end of slurry pipelines. Should we diversify them up, break up these regional electric grids, and go to smaller, more localized grids. The legislative thing right now is to switch to a national grid, so I think there are going to be other things that need to be considered here along the way, regarding technology. Also there is the idea of all these various states contributing their fair share. For example, Montana exports about 1/3 of their electricity and we ship part of our electricity, the majority going west in nice clean transmission lines. On the other hand

we ship our dirty coal East to form electricity. Again, who is to say what our fair share of contribution to, for example, the northwest power pool for the states of Washington, Oregon and Idaho. What's our fair share as far as contributing to the Eastern coal interests? Granted, we are burning one within the state and we are shipping one out of the state. I am just trying to broaden your question a little bit, but we need to decide which way we want to go on this thing. Certainly, if we are going to make our grid systems bigger, in other words, get larger regional systems, being able to transfer electricity from one region to another, then we need to change our ideas of how we are going to approach the thing as far as solar, biomass and this type of energy development.

LYNN DICKEY

I don't think it's an answerable question. I think that methods to determine the necessity for increased coal leasing, and methods to determine the necessity for increased electricity production vary state by state. Now, in Wyoming we have so much coal leased right now that we could produce 200 million tons a year for the next 20 years. It seems it is sort of a moot question in Wyoming as to whether there is actually a need for increasing the leasing of coal. That situation varies greatly from state to state and as far as assessing the need for power production is concerned, that's something that we're trying to grapple with in our state right now. Whose power needs are we going to consider when we decide whether or not Wyoming should have a new power plant located in it. There is no formula and I don't think that there can be a formula developed.

JOHN VEIGEL

Excuse me, given the lateness of the hour I'd like to ask you to come up afterwards if you want so that we can get to some other questions here.

DON PETERSON

I'm with the California Energy Commission and the University of

San Diego. I simply wanted to apologize for the oversights of the program committee of not having invited a native American to participate in this particular panel. As a proposed solution, we will invite written comments from that sector and incorporate them into written proceedings which will be distributed later.

IKE EASTVOLD

I'm representing the California Desert Region for the Sierra Club. It was mentioned, I believe, that in some part of Montana Mr. Stevens had found it just about impossible to revegetate certain areas that were arid. I would like to direct the question to Montana, Wyoming and Arizona in particular. What assistance or what hinderance might the new strip mining legislation be to you in revegetation of any of your problem areas?

LYNN DICKEY

It's of no particular hinderance or assistance. The Wyoming statute is virtually equivalent to the Federal Strip Mining Statute, with the exception of protection of alluvial valley floors (stream bottoms). Those areas of the state are given additional protection by the Federal Strip Mining law.

MICHAEL STEVENS

I was just going to say that it will assist us by placing more emphasis in those particular critical areas. We are also developing, as time goes along, a little better approach to just what some of the slopes ought to be as far as reclaiming some of these areas. I think that factor along we are learning a lot more. Anything in the near future will help us out.

TOM LYNCH

In Arizona the percentage of Indian ownership of coal is 100%. Hopi and Navajo tribes own the coal resource so we're not directly involved in that.

SUSAN LUCKY MOORE

I come from Twenty-Nine Palms in the California Desert. I represent a thing called Morongo Basin Conservation Assn. It is a local organization that takes care of that particular section of the desert, trying to keep it a good, pleasant, happy, healthy place to live. I'm feeling very much in empathy with some of the statements made by some of these people, particularly the lady from Wyoming. Our part of the country, I'm afraid, may suffer a similar fate as some of the big stir-up population and disturbance in small rural communities etc., which has been experienced in Wyoming and New Mexico. We have very clean air out in the very far east part of the California desert, which we are anxious to keep. Coal seems to be the biggest threat to the clean air. The past experience of the power plants, built in New Mexico and Arizona, has not added to my assurances; that it won't be very bad for our area if polluting coal plants are built out there. From all I have been listening to at this meeting, the techniques of keeping coal clean are not too well established or proven as yet. What power plants have shown that it will be clean? The ones that have been built in those states certainly have not. We'd like to have it limited somewhat as to how this takes place. I'd like to have all the alternatives analyzed carefully, as the lady from Wyoming said, "What about the other alternatives?" If coal development still needs so much done to perfect these clean technologies what about going ahead with some of the other techniques like solar development. Photovoltaic? Solar, for example, would be an ideal answer to some of the problems concerning water, which is one of the leading problems that we have about energy development in the desert. If it is going to take so much money and so much effort to make coal successful as a clean energy producer, why not put some of that effort into solar development. It seems to me that's an ideal development of resources for the Southwestern states. We have about the best solar energy available in one of the three best areas in the world where I live for this and I hate to see a lot of money and effort going to development of coal when its not

absolutely assured that it can be clean. I think there should be just as much work done for solar development which is a really good resource in these areas.

JOHN VEIGEL

Thank you for your comment. I would like to respond to it because of my own work. First your comments are well taken. The state has been doing that. My own estimates show that over the next two decades about one third of California's incremental capacity addition needs could be taken care of by the various alternative resources from geothermal through solar through biomass and wind etc. However, the one that you specifically mentioned photovoltaics is still too outrageously expensive (although prices have gone down) to be a viable option in any except the most remote kinds of applications.

SUSAN LUCKY MOORE

Could I make a comment on that. When you take a coal plant and put all of these new technologies into it, aren't they expensive? Don't these air pollution preventatives cost a lot. Also since you can eliminate cooling towers with a thing like photovoltaic, you can eliminate the excessive water use. You can eliminate having a generator, which is costly. When you count those things up against the cost of the photovoltaic cells, couldn't you go ahead with some experiments in photovoltaic that would begin to get it going?

JOHN VEIGEL

We would like to do some of that but even to do all of what you have asked for, cells are still a number of times more expensive than the other alternatives that we have either conventional or the so called softer technologies.

REED SEARLE

Let me give an example of the cost of photovoltaic electricity. The Department of Energy and the Parks Service in the State

of Utah are going to construct the world's largest photovoltaic facility just outside of Natural Bridges National Monument to provide all of the electricity to the facilities in that part because of its remoteness.

The project which will cover 1.2 acres of land with the sales photovoltaic cells, will cost slightly over 3 million dollars, and will provide sufficient electricity for 12 to 20 households. The heating oil or butane to provide the electricity through turbines for those households cost about \$10,000 a year. So somehow you have got to get the economics down so that you can capitalize this solar facility and have it come out to an annual operating cost of approximately \$10,000 a year. That, of course, is what these kind of projects are aimed at doing. They will decrease the prices substantially, but it is going to take a while.

SUSAN LUCKY MOORE

Mass production brings down prices of things like solar cells doesn't it?

JOHN VEIGEL

Yes man, it brings it down some, but if you have further comments on that part I would like to have you come up afterwards. We have got one question in the center and I would like to try to finish here.

RON RUDOLPH

I am with Friends of the Earth. Many speakers made mention of air quality considerations in their state as being important to the economic growth of the state. The Department of Interior has recently proposed the redesignation of National Monuments, primitive areas, and national preserves to class 1 designation under the prevention of significant deterioration of air quality provisions of the Clean Air Act. I was wondering if each of the panel members could say whether or not their respected states was supporting the redesignation of those national monuments and if not, why not?

JOHN VEIGEL

I would like to just take a couple of states rather than just everyone commenting. How about Utah, New Mexico and Arizona especially.

REED SCARLE

Utah, in most cases, is objecting to reclassification of national monuments, primitive areas, etc. We have a number of national parks in the state. Those are already class 1 areas. Our national parks and monuments and so on, just happen to be located on the same geographical regions as do all of our mineral resources. Man cannot detect the differences between class 2 air and class 1 air. It takes a rather sophisticated computer analyses. The modeling that we have been doing in the state of Utah indicates that in some cases even the modeling results that identify class 1 areas can be conservative to factors of ten. So we feel that as far as visibility and health related aspects are concerned, class 2 in those areas that have extremely few numbers of people, mainly tourists, is not going to allow adverse impacts upon the visibility of those areas nor upon the health of the people visiting the areas.

TOM LYNCH

I think Arizona might best respond by indicating that prior to any such reclassification, more than 80% of our land, because of federal Indian trust and other requirements, already is class 1, it is therefore almost impossible to construct any large polluting source in the state. There is not a utility in the nation that does not consider Indian land as class 1 lands because of their authority now to reclassify.

JIM HAMM

I'm with the C.F. Braun Co. I have one question that hasn't been addressed to the panel. These people have all had experience with recent coal fired plants that were built in their state to every rigid standards, Coal Strip in Montana, and San Juan in New

Mexico. I wonder if they might want to make any final comments as to whether or not coal plants can be good neighbors, if they can be clean and if its a rational approach to power?

MODERATOR

Who would like to handle that easy question?

MICHAEL STEPHEN

As far as Montana is concerned, their Coal Strip 1 and 2 are good neighbors. I say that kind of facetiously because fortunately they're not in a populated area. They are in a remote area of Montana which almost puts them into North Dakota. That's how the rest of the state look at it. If you had Coal Strip 1 or 2 in the Great Falls area or some populated area it would be different. We have found that our air pollution monitoring, as far as the state is concerned, needs a little bit more bite in it. We are somewhat satisfied with the results of how Coal Strip 1 and 2 are operating.

REED SEARLE

All of the electricity produced in the State of Utah, with the exception of about 3% of the state's power, is produced in coal fired power plants. Utah consumes about 2400 megawatts in power produced in coal fired power plants. The power plants are pretty good neighbors. The State of Utah's Bureau of Environmental Health have imposed state standards traditionally that have been more stric than the federal standards. Presently they are the federal standards. While I can't give you the actual pollution data, Utah Power and Light continues, and demonstrate to people the cleanliness of their plants by challenging bureaucrats, environmentalists and others to guess which of the stacks, one under construction, one in operation is in operation. In only one instance in about half a dozen flights over some of their power plants have I been able to detect which one is in operation and which one is not.

So the visible pollution from power plants in the State of Utah is minimal. We have not had a coal fired power plant in operation

within the limits of Salt Lake City for a number of years and that does cause a small problem, but it is not significant enough yet where it has been required to go through any modifications to clean it up. So, its not very bad.

NICK FRANKLIN

I don't think my answer will vary too much from the two previous gentlemen. We work quite well with industry in terms of the activities of the San Juan Plant. We are somewhat pleased with that.

My concern, in the long run, is this solar voltaics and the whole solar question that the lady was addressing. I think, of course, this is 20, 25 or 30 years off but we are going to run out of oil and gas. I think the options of coal or nuclear will go completely to coal. Even though we clean them as far as the technology advances, my concern is not the volume of the nonvisible pollutants is something that we may not want to live with. I personally feel that we have to develop both nuclear and the coal to at least have the options there. But at least in terms of the San Juan Plant, we are pleased with the activity there although there are still concerns. If you ask the people in the Farmington Area, obviously there are very happy because of the economic tradeoffs. If you ask the people in the Albuquerque area where one finds most of that pollution, there is a different attitude.

MODERATOR

Lynn, after you answer this question, I'd like to ask for any final comments from any of the panel members and then we will terminate.

LYNN DICKEY

The biggest problem in Wyoming, as far as air pollution from coal fired power plants is concerned, has to do with the frequency with which we have thermal inversions in a lot of the areas in the state. That certainly is a problem that California is going to have to take a look at as well. The existing coal fired power plants that we have right now are in areas where there are infrequent thermal inversions. The most recently proposed 2000 megawatt coal fired power plant for

the state is in an area where there are frequent thermal
inversions and of course that increases both the health and aesthetic
damage that is done by sulphur dioxide and particulate emissions
particularly from the plants in the state.

SESSION VI

**AIR POLLUTION CONTROL
AND COAL TECHNOLOGY**

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D. P. Teixeira
Electric Power Research Institute
Palo Alto, California

N79-27609

ABSTRACT

The status of technologies for controlling emissions of oxides of nitrogen (NO_x) from coal-fired power plants is reviewed. A discussion of current technology as well as future NO_x control approaches is presented. Included in this latter category are advanced combustion approaches as well as post-combustion alternatives such as catalytic and non-catalytic ammonia-based systems and wet scrubbing. Special emphasis is given to unresolved development issues as they relate to practical applications on coal-fired power plants.

I. INTRODUCTION

Oxides of nitrogen are a subject of general interest in California and of particular interest in Southern California. In this paper the various control technology options available for power plant applications are discussed. The discussion is primarily oriented around direct pulverized coal utilization,

though much of what will be said applies to other combustion devices and fuels as well.

II. BACKGROUND

Oxides of nitrogen from combustion sources are composed of nitric oxide (NO) and nitrogen dioxide (NO₂). Together they are referred to as NO_x. From an effects standpoint, it is mainly the NO₂ and its derivatives which are of concern. However, from a control technology standpoint, it is the NO which is of interest since the majority of the direct emissions of NO_x from power plants are in this form.

There are two sources of nitrogen which can lead to NO_x formation. The first is molecular nitrogen (N₂) carried along with the oxygen in the air. At high combustion temperatures this normally inert N₂ can react with oxygen to form NO_x. Since this occurs at high temperature, it is frequently referred to as

thermal NO_x. Control of NO_x from this nitrogen source is reasonably well established technology. The other source of nitrogen is that inherently bound within fuel molecules. Because earlier thermal NO_x control measures are relatively ineffective for this nitrogen source, it is the inherent nitrogen which makes NO_x control difficult on any fuel containing significant quantities of nitrogen. Coal falls into this category since it typically contains 1 to 1-1/2% nitrogen by weight.

III. CURRENT TECHNOLOGY

At the present time, operational modifications to the combustion process are the only commercially available means of controlling NO_x emissions from coal-fired power plants (Table I). This usually involves some form of staged combustion (NO_x ports, overfire air ports, burners out of service) or low NO_x burners both of which are aimed at minimizing the quantity of oxygen available for combination with air or fuel nitrogen sources. Combustion techniques specifically aimed at reducing thermal NO_x (flue gas recirculation, reduced air preheat, water injection) are relatively ineffective when applied to coal-fired boilers.

Considerable testing of coal-fired boilers, mainly by EPA, has shown that current regulations of 0.7 lb/10⁶Btu (about 500 ppm for coal) can be achieved. However, from an operating standpoint, significant questions regarding boiler corrosion and slagging are still unanswered. EPA has proposed that the standard be lowered to 0.6 lb/10⁶Btu. This has prompted considerable discussion, since the ability to reliably meet the 0.7 lb/10⁶Btu standard still has not been proven.

Currently, boiler manufacturers are investigating burner techniques for controlling NO_x to 0.6 lb/10⁶Btu and lower levels. However, the ability to meet these levels is unknown, as are important reliability issues similar to those discussed above.

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Emissions in the 250-300 ppm range have been reported in one Japanese coal-fired installation. This has been accomplished through advanced burner designs and staged combustion. Long-term reliability issues have not been released.

IV. ADVANCED TECHNOLOGY

Reduction in emissions beyond the levels cited above will require innovative new technologies. Both advanced combustion process techniques as well as post-combustion approaches such as catalysis or scrubbing are currently under investigation.

A. COMBUSTION MODIFICATION

There is a considerable body of basic data indicating that nitrogen in coal can be prevented from forming NO_x by manipulating the combustion process. Properly done, the nitrogen in the fuel can be reduced to harmless molecular nitrogen.

The fundamental requirement to accomplish the desired effect is through combustion under controlled reducing conditions. One such approach to this problem is shown in Fig. 1. Pulverized coal is introduced into a burner with less air than required for complete combustion. A key feature of this approach is the physical isolation of the reducing zone from the oxidizing zone, which permits accurate control of process stoichiometry. The extended length of the combustor provides the necessary residence time to partially oxidize the coal and permit desirable N_2 -forming reactions to occur. Heat removal also occurs along the combustor to avoid slagging and for process temperature control. Secondary air is added at the exit of the extended furnace to bring the combustion products to oxidizing conditions for the balance of their passage through conventional steam generating equipment.

Development of this process is being conducted at two scales. Preliminary screening tests are being done at approximately 4×10^6 Btu/hr (0.4 MW). Prototype development will then be done at 10×10^6 Btu/hr (5 MW).

Results of this research are only now becoming available. Typical results from the 4×10^6 Btu/hr scale give about 150 ppm for a typical western subbituminous coal. While extrapolation of experience at the laboratory scale to full-scale burners (typically on the order of 200 x

10^6 Btu/hr) must be approached with caution, the results to date must be viewed as encouraging. Considerably more research into scale-up effects, slagging, corrosion, safety, and general operability-reliability aspects will be required. Commercial availability is scheduled for the early to mid 1980s time frame. Preliminary cost estimates for the low NO_x combustion system are estimated at about \$5/kW for new installations.

B. POST-COMBUSTION CONTROL TECHNIQUES

Even if the advanced combustion techniques are 100% successful, it is unlikely that NO_x below the 100-200 ppm range can be achieved. If emissions below this level are deemed necessary, post-combustion processes will probably be required.

Post-combustion systems fall into two major categories: dry ammonia (NH_3) based and wet scrubbing. The NH_3 systems are further broken down into catalytic and non-catalytic technologies. Some dry systems can be used to collect NO_x and SO_x . The wet scrubbing systems can be used for NO_x alone, but almost always involve simultaneous NO_x and SO_x removal for economic reasons. However, comparatively little work has been done on wet scrubbing relative to dry processes. For both NH_3 and scrubbing processes, the vast majority of work has been done in Japan, where stringent NO_x standards have been imposed.

1. Catalytic NO_x Control with NH_3

Catalytic reduction of NO_x with ammonia (NH_3) is selective; that is, NH_3 preferentially reacts with NO_x over other compounds according to the following hypothesized overall reactions:



As can be seen, only gaseous N_2 and H_2O are the theoretical products.

A schematic diagram of a typical catalyst application in a coal-fired boiler is shown in Fig. 2. The catalyst is physically located between the boiler economizer and the air preheater. Such a location is necessary since required catalyst process temperatures are in the 700-800°F range. As can be seen, the catalytic system involves reactors and ductwork of significant size. A graph of the NO_x removal efficiency as a function of temperature for a typical catalytic system

is shown in Fig. 3. The heat of the flue gas downstream of the air preheater to provide these temperatures is viewed as impractical.

In Japan, a significant number of catalytic processes have been investigated on flue gas from natural gas and oil-fired boilers, and NO_x reductions of 90% have been reported. However, only limited data are available for flue gas having SO_2 and particulate levels characteristic of U.S. coal-fired applications. Acknowledged research to date has only been at the several hundred cfm (0.1 MW) to several thousand cfm (1 MW) scale.

In addition to the basic question of scale-up, there are several key development issues which remain to be solved regarding catalytic NO_x removal. Table II summarizes these issues, along with the technical problems that are created, potential solutions, and a qualitative estimate of costs.

a. Dust Tolerance

One major development issue is related to the quantity of fly ash associated with coal. Particulate load in coal-fired boiler gases is about 1000 times that for oil. This means that conventional packed bed contacting designs are not practical, since they would physically plug up.

A solution to the dust problem can be addressed from two standpoints: elimination of the fly ash by using a hot electrostatic precipitator upstream of the catalyst; or development of dust-tolerant contacting geometries. In practice a dust-tolerant catalyst is probably required in any event because precipitator filter operating upsets which produce transient particulate concentrations cannot be completely eliminated.

Research into catalyst contactor configurations which are tolerant of full coal-fired dust concentrations has begun in Japan. While some schemes involve moving beds, the more promising approaches are what is frequently termed a parallel passage reactor. In such a contactor the reactor walls are oriented parallel to the direction of flow. This permits diffusion of the NO_x and NH_3 to the active catalyst sites at the walls, while the dust particles continue flowing with the bulk gases. Parallel passage reactor configurations under investigation include pipe, honeycomb and corrugated. Because of the competitive nature of these developments, only limited public information is now available regarding details of the time-

dependent performance of these devices over catalyst lives of commercial interest. The success in achieving erosion and plugging resistant geometries will be known as data is published.

It is worth noting that extrapolation of coal-fired catalyst data to coal, and vice versa, must be approached with caution. In addition to the differences in particulate loadings noted earlier, the fly ash chemical composition (carbon, trace elements, and acidity) and physical characteristics ("stickiness") are also quite different between the two fuels.

Another problem which must be addressed even in a parallel passage reactor is the problem of physical blockage of the small openings of the reactor. It may be necessary to provide some form of particulate removal -- such as an impaction plate or cyclone -- to prevent impingement of large fly ash agglomerates on the catalyst. The requirement of such a device would obviously increase the costs of the catalytic system.

b. NH_3 Carryover

Another significant problem that must be successfully resolved before catalytic systems can be viewed as applicable to coal-fired boilers relates to the carryover of unreacted NH_3 from the catalyst. In addition to being an undesirable emission by itself, NH_3 can react with SO_2 to form sulfates or bisulfates which could also be emitted to the atmosphere. From a utility operating standpoint, an even more pressing problem is the formation, condensation and subsequent deposition of ammonium bisulfate on low-temperature heat recovery components downstream of the catalytic reactor.

Deposition of this material is undesirable since it will result in increasing pressure drop leading to subsequent reduction in the generating capacity of the plant. The material is also suspected to be corrosive.

An equilibrium graph showing the temperature dependence of bisulfate formation as a function of SO_2 , H_2O and NH_3 is illustrated in Fig. 4.

Prevention of bisulfate deposition may be accomplished via lowered NH_3/NO stoichiometries (which lowers NO_x removal), or a catalyst which decomposes NH_3 . At least one Japanese company is researching an NH_3 decomposition catalyst.

c. Low Load Operation

Bisulfate deposition can also be a problem within the catalytic reactor itself when temperatures drop below the condensation point such as occurs at low load operation. Potential solutions include maintaining the catalyst at temperatures above the bisulfate point by incorporating high temperature flue gas bypass or higher catalyst operating temperatures. The effectiveness of the catalysts at higher temperatures is not known.

d. Automatic Control System

Another engineering problem which requires attention is the ammonia injection control system. Japanese systems typically use feed forward control only based on inputs from oil-fuel flow, O_2 concentration and inlet NO_x . Environmental, economic and operating considerations in U.S. applications will probably dictate that the control system additionally incorporate as a minimum a feedback loop based on reactor outlet NH_3 and NO_x .

e. Environmental Issues

One final point should be noted. Since the objective of any catalytic NO_x process is to improve the environment, care must be taken to assure that potentially undesirable byproducts are not released in the process. In addition to NH_3 , ammonium sulfate and bisulfate mentioned earlier, emissions of N_2O (the result of incomplete reduction of NO_x), SO_3 (caused by oxidation of SO_2 over base metal catalysts), amines and other compounds have yet to be evaluated.

On the basis of personal discussions with Japanese vendors, economics range from \$10-80/kW, averaging \$30/kW. However, in many cases it is not clear whether this cost covers equipment only or installation. It almost certainly does not include IDC, G&A and other owner overheads. Besides these basic questions and those which always exist when extrapolating limited pilot plant data to commercial applications, there are other factors which confuse the cost picture. For example, differences in labor rates and productivity and raw material costs between Japan and the U.S. make it difficult to accurately judge costs by simply converting from yen to dollar at the current exchange rate. Other factors could also lead to substantially different costs, such as OSHA requirements and general operating philosophy. EPRI

currently has projects aimed at accurately defining the cost of catalytic technology for U.S. power plant applications. This information is expected to be available later this year.

Current research activity on catalytic NO_x systems is at a fairly low level. EPA has just awarded a contract to a Japanese vendor for research on a 1/2 MW pilot plant. EPRI intends to perform research at the 2-1/2 MW scale. Discussions with vendors are currently under way. A major feature of this research will be the systematic investigation of the major development issues noted earlier.

2. Non-Catalytic NO_x Control with NH_3

In addition to the catalytic systems, research is also underway on noncatalytic NH_3 -based NO_x control technology. Conceptually, the noncatalytic system is attractive; all that is required is NH_3 and an injection system. The catalyst is eliminated. NH_3 is injected at the proper temperature and the NO_x and NH_3 selectively and homogeneously react, probably according to equations 1 and 2. The relatively narrow temperature range over which the process is effective is seen in Fig. 5 for an oil-fired laboratory experiment. This narrow temperature range makes it somewhat difficult to apply the technique, since the temperature at a single point in a boiler can vary significantly with fuel fluctuations, ash deposits, operating conditions, and load. Solutions to the temperature sensitivity problem include multiple injection sites, moveable injection probes or hydrogen addition. The likelihood of this latter technique for utility applications is not well defined.

The most significant application to date of the noncatalytic technology is the 375 MW full-scale installation at the oil-fired Chita plant of Chubu Electric in Japan (Fig. 6). This unit uses multiple injection sites to provide temperature variation flexibility. The NO_x reduction, NH_3/NO ratio, and NH_3 carry-over are shown in Figs. 7 and 8 as a function of load. The unique shape of the curves with load is due to temperature variations with load and the use of two NH_3 injection points. NH_3 carry-over is high especially at low load and may limit the NO_x reduction in U.S. applications.

Air preheater deposition at Chita has not been a problem due to the low (1-2 ppm) SO_3 levels associated with the 0.2% S oil used. Feed forward control based on oil flow, inlet NO_x , and excess

O₂ is used. As with the catalytic approach, U.S. utility operating practices will probably dictate the addition of a feedback loop as well.

The currently available data for coal firing is shown in Fig. 9. These data were obtained on a 3 x 10⁶ Btu/hr laboratory facility. The variation in optimum process temperature with unidentified coal and/or ash characteristics shown may complicate the ease of practical application.

The noncatalytic technique has removal efficiencies which are lower than the catalytic approach, higher NH₃ consumption, and higher NH₃ carry-over. Problems associated with NH₃ carry-over have already been discussed and need not be repeated.

3. NO_x Scrubbing

Control of NO_x in a scrubbing process is attractive because potentially two emissions of concern (NO_x and SO₂) can be controlled simultaneously. However, scrubbing of NO_x is limited by the insolubility of NO in most scrubber liquors.

Two general approaches have been devised to get around the NO insolubility problem: conversion of the NO to more soluble species and use of an NO "getter" in the scrubber liquor.

Oxidation of NO has been explored with hypochlorite and O₃. However, because of water quality considerations, only O₃ is of interest. However, O₃ production is expensive and energy-intensive. In addition, the oxygenated NO_x is not that soluble and large vessels and/or large liquid-to-gas flow rates are required to perform absorption. As an alternative to extremely large vessels and L/G's, the addition of catalysts has been considered. For the typical flowsheet shown in Fig. 10, CuCl₂ and NaCl are used. Both of these materials again raise questions of water quality. Additional water quality concerns relate to potential byproducts of the process, such as monodisulfonate and dithionate. Consideration of these factors has led at least one research organization in Japan to halt further development.

The other major category of wet processes involves the use of ethylene diamine tetraacetic acid (EDTA) to form reactive adducts with NO. The process flowsheet is shown in Fig. 11. These processes also form potentially undesirable byproducts similar to those in the O₃ system. The major development issue in

wet systems is regeneration of the EDTA. A viable approach has not yet been reported.

Even if the issues noted above can be overcome, there is one overriding consideration which must be addressed. This relates to the feasibility of the process on low-sulfur coals. Reduction of the NO via EDTA or O₃ occurs through reaction with sulfite ion which is inherently low on scrubbers applied to low-sulfur coal. It is postulated that an SO₂/NO_x ratio of greater than 2-1/2:1 must exist to effect the process chemistry. Typical western coals are on the order of 1:1 or 2:1. These ratios could make for low NO_x removal efficiencies. Alternatively, SO₃²⁻ reagents could be added, but this is viewed as economically unattractive.

V. CONCLUSIONS

Development of NO_x control technology for coal-fired power plants at the pilot plant scale is just now beginning in the U.S. Direct extrapolation of Japanese experience both economically and technically should be approached with caution.

The most cost-effective solution to NO_x control will continue to be combustion modification. If greater control than can be provided by combustion control is necessary, NH₃-based systems have an advantage over scrubbing systems, although considerable technical hurdles are yet to be resolved.

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Table I

CURRENT NO_x TECHNOLOGY

<i>Modification</i>	<i>NO_x Level PPM</i>	<i>Unresolved Issues</i>
• Operational Combustion Changes	• 550	• Corrosion, Slagging, Byproduct Emissions
• New Burners	• Below 550	• Corrosion, Slagging, Byproduct Emissions, Effect of Coal Type
• Reported Japanese Data	• 250 - 300	• Accuracy of Data Unknown

Table II

CATALYTIC NO_x CONTROL

<i>Development Issue</i>	<i>Practical Problem</i>	<i>Potential Solutions</i>	<i>Qualitative Cost Impact</i>
• Dust Loading	• Catalyst Bed Pluggage/Erosion	• Parallel Passage Reactor with Inertial Separator • Hot Electrostatic Precipitator	• Large • Large (possibly impractical)
• NH ₃ Carryover	• Environmental Emissions • Air Heats Deposition/Corrosion	• NH ₃ Decomposition Catalyst • Lower NH ₃ Feed (lowers NO _x removal)	• Large • Small

Table II (Contd)

**CATALYTIC NO_x CONTROL
(continued)**

<i>Development Issue</i>	<i>Practical Problem</i>	<i>Potential Solutions</i>	<i>Qualitative Cost Impact</i>
• Low Load Operation	• Catalyst Pluggage	• Economizer Bypass • High Temperature Catalyst	• Large • Large
• Automatic Control	• NH ₃	• Feedback Control	• Small
• Byproduct Emissions		• Unknown	• Unknown

CONCEPTUAL APPLICATION OF EPRI/B&W LOW NO_x COMBUSTOR

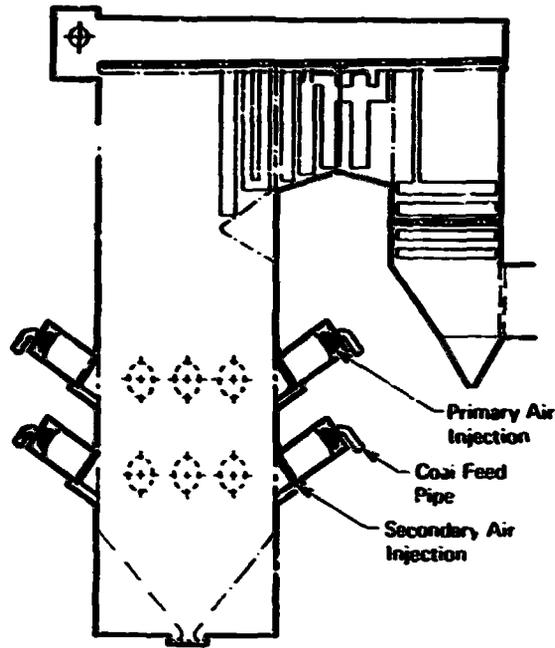


Figure 1

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CATALYTIC NO_x APPLICATION TO COAL-FIRED PLANT

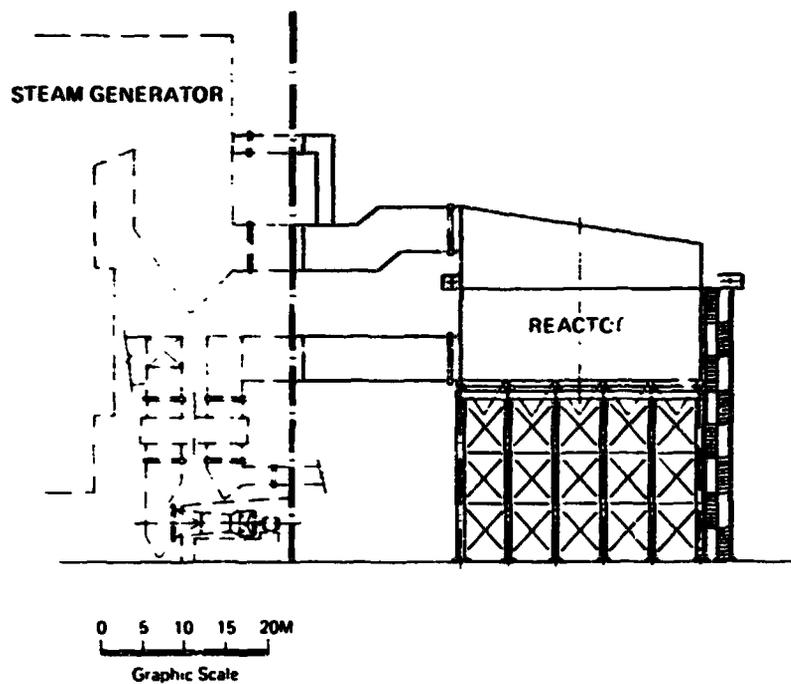


Figure 2

**NO_x REMOVAL VS TEMPERATURE
CATALYTIC NO_x SYSTEM**

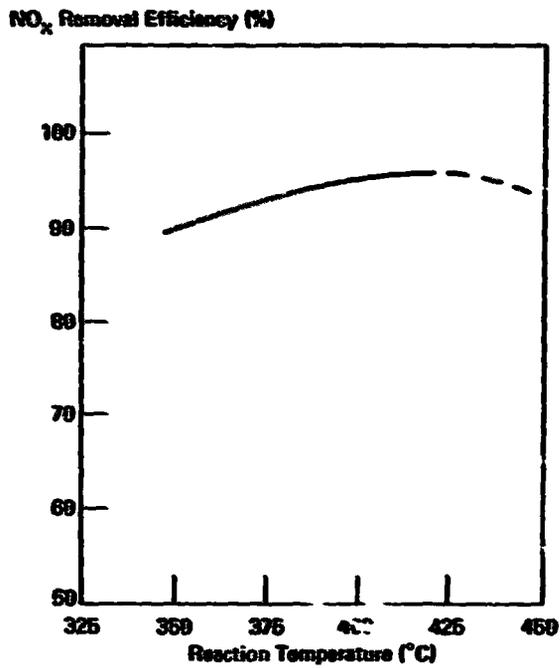


Figure 3

**FORMATION TEMPERATURE
OF NH₄ HSO₄**

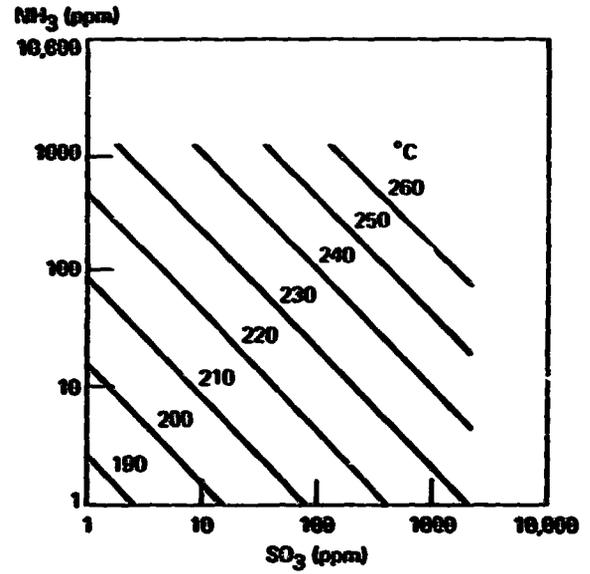


Figure 4

**OIL-FIRED NO REDUCTIONS WITH NONCATALYTIC
AMMONIA INJECTION
LABORATORY DATA**

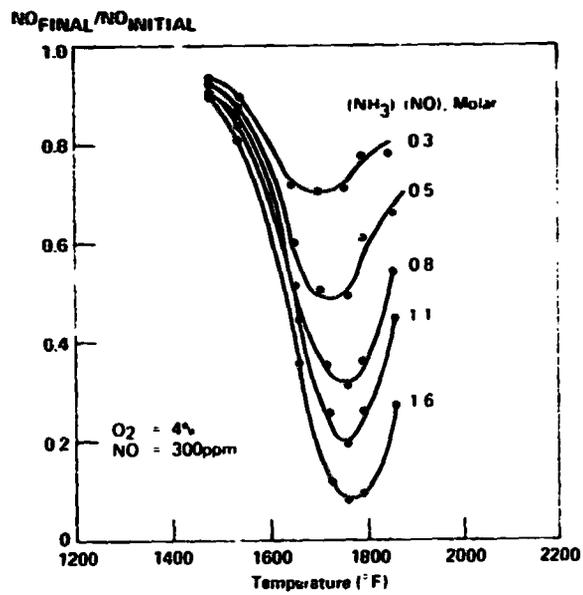


Figure 5

NONCATALYTIC NO_x REDUCTION WITH AMMONIA - CHITA UNIT 3

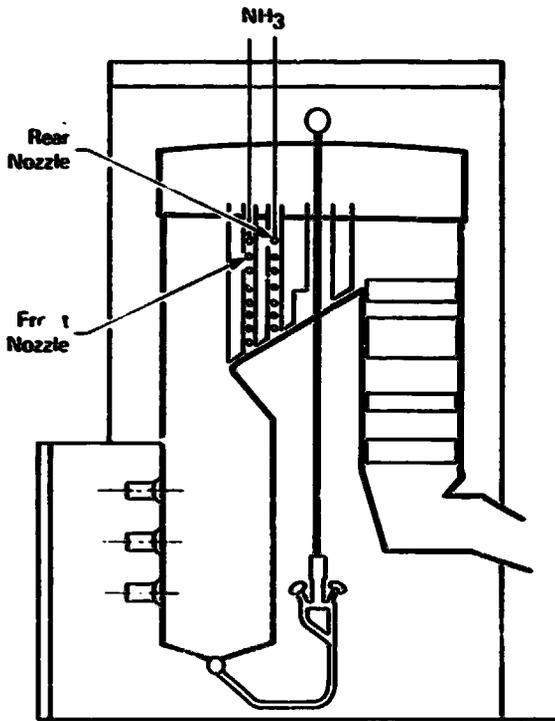


Figure 6

NH₃ CARRYOVER - CHITA UNIT 3

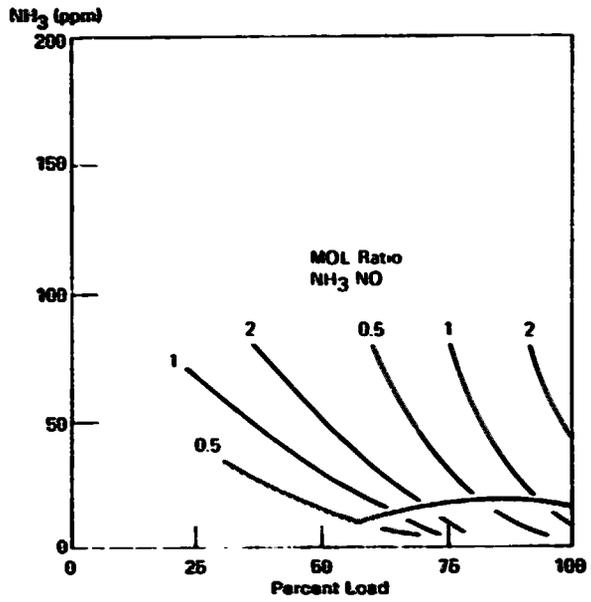


Figure 8

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NO_x REDUCTION PERFORMANCE - CHITA UNIT 3

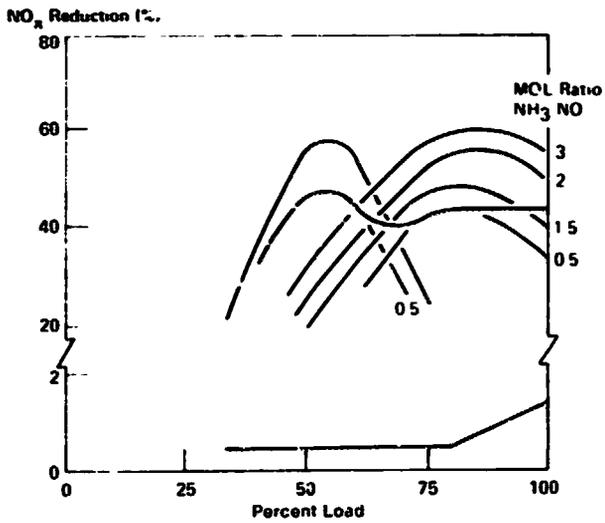


Figure 7

COAL-FIRED NO REDUCTION WITH NONCATALYTIC INJECTION LABORATORY DATA

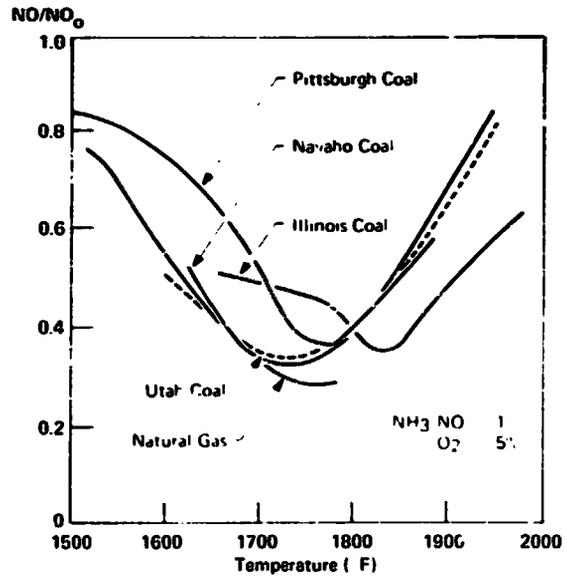
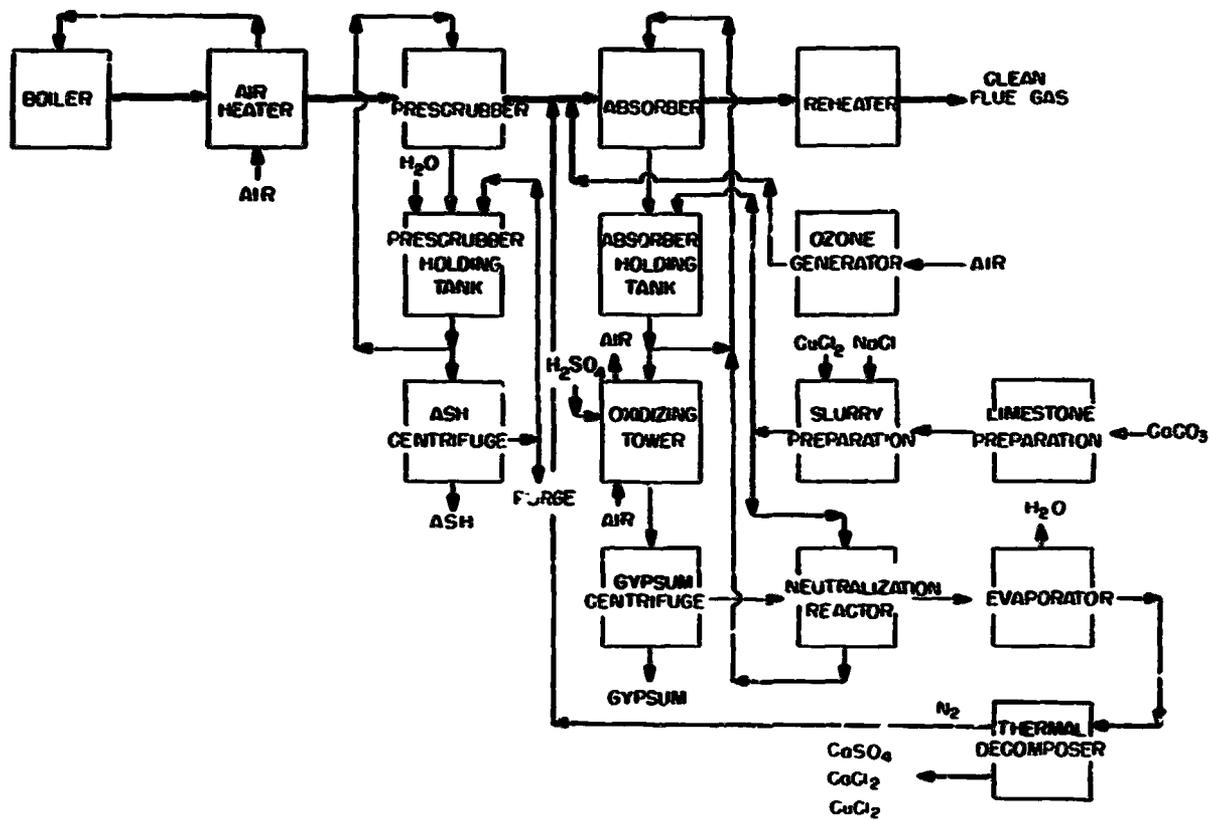
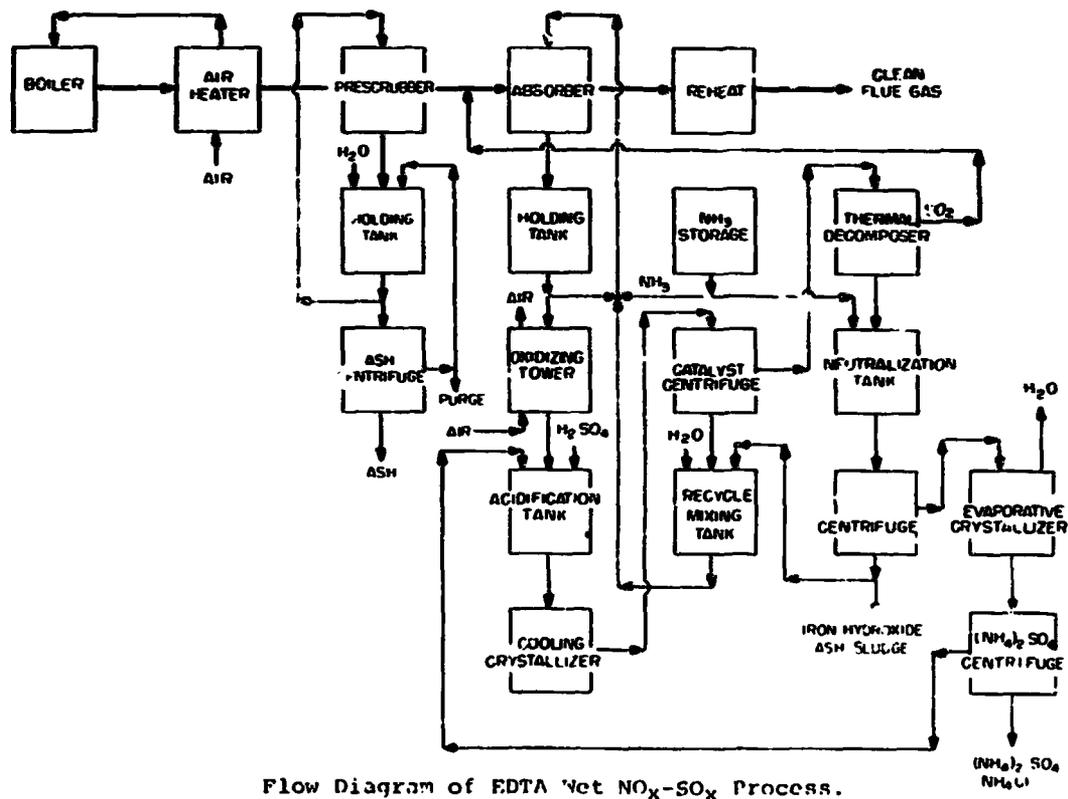


Figure 9



Flow Diagram of Ozone Wet NO_x - SO_x Process.
Figure 10



Flow Diagram of EDTA Wet NO_x - SO_x Process.
Figure 11

ENGINEERING UPDATE FOR FLUE GAS DESULFURIZATION TECHNOLOGY

Frank Princiotta

Environmental Protection Agency

Currently, the utility commitment to FGD technology is estimated to be of 50,000 MWe. Lime and limestone scrubbing systems predominate. An examination of the durability of on-line FGD systems indicates a consistent trend in improved reliability for the more recent installations. Despite the improving performance, certain problems are encountered: mist eliminator plugging, reheater corrosion, stack liner

corrosion, and instrumentation problems. An examination of the operability of Japanese FGD technology applied to coal-fired boilers indicates excellent performance; all five units are operating at greater than 95% reliability since startup. For new high-sulfur, coal-fired utilities larger than 500 MW, investment requirements will average 80 to 100 \$/kW. Annualized cost requirements will average 4 to 5 mills/kWh.

NOTE: The complete paper was not available at the time of publication.

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PARTICULATE CONTROL FOR COAL-FIRED UTILITY BOILERS

Stanton Cowen

Meteorology Research, Inc.

The more stringent limitations for particulate emissions necessitates an in-depth look at the best available control technology. This paper examines the three major types of particulate control devices currently in use: electrostatic precipitators, fabric filter baghouses, and wet scrubbers. The current state of technology and research conducted at Meteorology Research, Inc. (MRI) will be reviewed. A preliminary comparison of per-

formance for western ash indicates that baghouses are much more efficient than either electrostatic precipitators or scrubbers. However, large-scale baghouses on utility boilers have not been demonstrated, although a number are under construction. Much more research and operating experience of fabric filtration on utility boilers is needed to demonstrate its viability as a long-term solution to particulate emission control.

NOTE: The complete paper was not available at the time of publication.

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N79-27610

ECONOMIC COMPARISON OF FABRIC FILTERS AND ELECTROSTATIC PRECIPITATORS FOR PARTICULATE CONTROL ON COAL-FIRED UTILITY BOILERS

Peter M. Cukor, Ph. D., Director

and

Richard A. Chapman, Senior Engineer

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Teknekron, Inc.
Berkeley, California

Abstract

This paper discusses the uncertainties and associated costs involved in selecting and designing a particulate control device to meet California's air emission regulations. The basic operating principles of electrostatic precipitators and fabric filters are discussed, and design parameters are identified. The size and resulting cost of the control device as a function of design parameters is illustrated by a case study for an 800-MW coal-fired utility boiler burning a typical southwestern subbituminous coal. The cost of selecting an undersized particulate control device is compared with the cost of selecting an oversized device.

Kern County's process weight rule, typical of many in California, is:

$$\text{allowed emissions (lb/hr)} = 17.31P^{.16}$$

where p = coal fired in tons per hour. Under this rule, an 800-MW unit burning 350 tons per hour of a typical southwest subbituminous coal with a heating value of 10,000 Btu per pound and containing 10 percent ash would be allowed to emit only 44.4 pounds per hour of particulates. This limit, equivalent to 0.0062 pounds per million Btu, would require a particulate collection efficiency of 99.93 percent - which is clearly not within the current state of the art.

California's Particulate Emission Limits

In California, as in most states, there are many particulate emission regulations for coal-fired utility boilers. Some of the regulations applicable in California include:

- (1) Federal new source performance standards.
- (2) New source review requirements for non-attainment areas.

Best available control technology.
Lowest achievable emission rate.
Emission offset requirements.

- (3) Process weight rules.
- (4) Local maximum emission rate rules.

Many of the process weight and local maximum emission rate rules are designed to prevent the construction of new coal-fired utility boilers. In fact, Scattergood Unit 3, a 309-MW gas-fired boiler owned by the Los Angeles Department of Water and Power, is just able to meet the local maximum particulate emission rate.

By the end of 1978, California will submit to the U. S. Environmental Protection Agency a new State Implementation Plan containing revised limits for the control of particulate emissions. It is expected that this plan will require new coal-fired plants to be equipped with the best available control technology (BACT), and that the BACT limit will be similar to the limit of 0.03 pounds per million Btu that EPA itself is considering. The California Air Resources Board expects promulgation of the new statewide limit to result in a relaxation of the numerous stricter local emission limits.

Uncertainties in the Selection and Design of Particulate Control Devices

Electrostatic Precipitators. Electrostatic precipitators (ESPs) have historically been used for the control of particulate emissions from coal-fired utility boilers. (Wet scrubbers, also historically used, are no longer usually selected: the very high operating pressure drops they need in order to achieve the collection efficiencies required by current and proposed new source performance standards result in uneconomically high operating costs.)

Electrostatic precipitators collect particulate matter by electrically charging the particles in the gas stream and then allowing the particles sufficient residence time in the ESP to migrate to the oppositely charged collecting plates. The collecting plates are periodically rapped to dislodge the collected ash, which slides into the collection hoppers. Figure 1 illustrates a typical ESP, showing the general configuration of the discharge electrodes, collecting plates, and ash hoppers. In this illustration, three stages of electrodes, plates, and hoppers are used.

The velocity at which the charged particles migrate toward the collecting plates determines the size and the resulting cost of the ESP. The higher the velocity, the smaller the size and the lower the cost. The velocity is dependent on numerous parameters, the most important of which are particle size and ash resistivity. High-resistivity ashes containing small particles are capable of accepting only relatively small electrical charges and therefore have a relatively low migration velocity. Figure 2 illustrates the resistivity of two typical coal ashes as a function of temperature. Note that medium-sulfur coal ash typically has a lower resistivity than low-sulfur coal ash. Likewise, high-sulfur coal ash usually has a lower resistivity than medium-sulfur coal ash. Note also that the ash-resistivity curve peaks at a temperature of about 400 degrees. From this curve we can see that, in order to obtain the low resistivity desired, the ESP must be located at a point in the system where temperatures are below 300°F or above 600°F. In a typical coal-fired boiler, gas temperatures are usually above 600°F upstream of the air preheater and below 300°F downstream of the air preheater, thus providing locations for hot-side and cold-side ESPs.

Both coal properties and boiler operating conditions introduce uncertainties into the design of an ESP. The primary coal properties of interest are the ash content of the coal and its resistivity. The ash content of coal from a single mine varies considerably from day to day; similarly, the resistivity may vary. If the coal source changes, as it may in the life of a coal-fired power plant, the changes in ash properties are often quite dramatic, especially if the coal sulfur content changes significantly. The primary boiler operating condition of interest is the boiler's anticipated duty. A base-load plant maintains a fairly constant exhaust gas temperature and flow rate, while a load-following plant often produces significant fluctuations in exhaust gas temperature and flow rate. These fluctuations affect the ash resistivity and velocity through the precipitator. Therefore, the designer of an ESP must consider both current and future coal supplies and plant operating conditions.

Design parameters for hot-side ESPs reported to the Federal Power Commission on FPC Form 67 are illustrated in Figure 3. The specific collector area (SCA) is an indication of the size of the ESP and is a function of the particle migration velocity and required collection efficiency. Note that, at a collection efficiency of 99.5 percent, the design SCAs vary between 260 and 746 ft²/1000 ACFM. This three-fold difference in SCAs is probably due to different design ash resistivities, but in the case of the two large SCA values it may also reflect the existence of a severe financial penalty to the vendor if the ESP does not meet strict performance guarantees.

Fabric Filters. Fabric filters, or baghouses, have only recently come into use for the collection of particulate matter from utility boilers. There are currently a few relatively small fabric filter installations on utility boilers and a few larger installations planned or under construction. Figure 4 illustrates a typical fabric filter module wherein the particle-laden gas enters the base of the filter and travels upward through the numerous bags that collect the particulate matter. The bags are periodically cleaned by diverting the gas flow to other modules and either shaking the bags or reversing the air flow through them to remove the collected ash.

The size and resulting capital cost of a fabric filter is a function of the gas velocity through the bags. This velocity is called the air-to-cloth ratio. Lower air-to-cloth ratios generally provide higher collection efficiencies at lower operating pressure drops and require larger-size installations for a given application. The design of a fabric filter involves a trade-off between the high capital cost for a low air-to-cloth ratio and the high operating (pressure drop) and maintenance (bag replacement) costs associated with a high air-to-cloth ratio. Bag material and cleaning frequency must also be included in the design trade-off.

Fabric filters are less sensitive than ESPs to variations in coal ash content and ash properties. However, uncertainties in the design of fabric filters still exist, primarily in relation to the pressure drop and resulting operating costs. Pressure drop, which depends partially on the shape and size distribution of the fly ash, can change significantly for a given fabric filter when the coal source is changed.

Performance Models for Electrostatic Precipitators

For a given application, the collection efficiency of an ESP is inversely proportional to the velocity of the gas parallel to the collecting plates, or directly proportional to the residence time of the gas in the ESP. This relationship is expressed by the Deutsch equation

$$\eta = 1 - \exp\left(-w \frac{A}{V}\right) \quad (1)$$

where

η = collection efficiency

w = migration velocity of the particles

A = collecting plate area

V = gas velocity parallel to the collecting plate

The relationship $\frac{A}{V}$ is often called the specific collector area (SCA), as indicated in the preceding section. The SCA, once determined, is multiplied by the gas flow rate through the ESP to determine the total collecting plate area required for a given collection efficiency.

The migration velocity, as mentioned previously, is very sensitive to particle size and ash

resistivity as well as to electrical conditions within the ESP. Most ESP designers use some form of the Deutsch equation to determine the required ESP size for a given application; and, since most designers use only one particle size instead of the particle-size distribution actually found in the gas stream, a great deal of experience is required in selecting the proper migration velocity. This design approach works fairly well when low-resistivity, high-sulfur eastern coals are used in boilers subject to relatively lenient emission limits. Unfortunately, however, the recent increase in the use of high-resistivity western coals combined with the increasingly more stringent particulate emission limits has forced the design of ESPs outside of the realm of experience of many ESP designers. This has resulted in the gross underdesign or overdesign of ESPs for western coals. Although the ESP business is very competitive, few performance guarantees have been required in the past. Consequently, most of the early ESPs for western coals were grossly underdesigned. ESP designers have subsequently modified the form of the Deutsch equation or substituted lower migration velocities in an attempt to model the performance of ESPs operating outside their realm of experience.

The SoRI Performance Model. To provide ESP designers with a better design tool, Southern Research Institute (SoRI) under contract with EPA has developed an ESP performance model that is based on the detailed physics of particle collection and considers the distribution of particle sizes (1). The SoRI model is quite complicated, and its 2,400 lines of computer code offer the designer little insight into the physical processes taking place in the ESP. While it is a vast improvement over the approach used by many ESP designers, the SoRI model calculates theoretical, or ideal, collection efficiency and still requires the designer to assume values for gas-flow maldistribution, gas leakage, rapping recirculation, ash electrical properties, and the internal geometry of the ESP, all of which contribute to the nonideal collection efficiencies encountered in the field.

The SoRI ESP model has been simplified and programmed by Sparks (2) for use with a programmable calculator. The simplified version considers the distribution of particle sizes encountered in the ESP and should be of great value to the ESP designer. It requires the use, however, of the SoRI computer model to generate numerical values for use in calculating particle migration velocities; several typical migration velocities as a function of current density are included in the Sparks report.

The Teknekron Performance Model. Teknekron has developed a correlating function for the overall efficiency of an ESP that can be used with experimental data to predict the efficiency of an ESP of given size. A brief description of the Teknekron ESP performance model is presented here; a thorough description has recently been published and should be consulted if more detail is required (3).

The approach suggested by White (4) for handling the effects of particle-size distribution on ESP collection efficiency is

$$\eta_1 = 1 - \int_0^\infty \exp\left(-\frac{A}{V} w(x)\right) P(x) dx \quad (2)$$

where $w(x)$ is the migration velocity as a function of particle size, $P(x)$ the particle-size frequency distribution, and x the particle diameter. The functional form of $w(x)$ is predicted by electrostatic theory to be linear with respect to particle diameter x :

$$w(x) = \frac{\epsilon_0 E_c E_p x}{\theta} \quad (3)$$

where ϵ_0 is a function of the particle dielectric constant, E_c is the particle charging field strength, E_p is the strength of the precipitating field, and θ is the gas viscosity.

The Teknekron model assumed that migration velocity is a linear function of particle diameter, i.e.,

$$w(x) = w_0 + w_1 x \quad (4)$$

The two parameters w_0 and w_1 characterize the coal used and make it possible to include the effects of thermal charging (as x goes to zero, w is finite). The resistivity of a given coal ash can be embedded in the parameters w_0 and w_1 , as demonstrated by Sparks (2).

The integration of collection efficiency with respect to particle size can be performed analytically for a number of functions of migration velocity if one employs semilogarithmic (or exponential) correlations for particulate loading and collection efficiency rather than the standard power law (log-log) correlations conventionally used in recording efficiency data. This method appears to entail a negligible loss of accuracy, even for 99.9-percent overall collection efficiencies. The analytical expressions for overall collection efficiency do appear to scale up reasonably well for field data, although any conclusions about the validity of the method should be reserved until more data become available.

The exponential distribution for inlet particle-size takes the form

$$P(x) = B \exp(-Bx) \quad (5)$$

which corresponds to the cumulative distribution

$$Y(x) = \exp(-Bx) \quad (6)$$

This cumulative distribution is defined as the mass fraction of particles having a diameter larger than or equal to x . Hence, $Y(0) = 1$.

The B 's calculated for representative distributions of fly-ash particle size for three boiler types are as follows:

Boiler Type	B
pulverized coal	0.040
stoker	0.017
cyclone	0.10

The Deutsch equation in terms of w can be written as

$$\eta(x) = 1 - \exp\left(-\frac{A}{V} w\right) \quad (7)$$

If $w = w_0 + w_1 x$, then:

$$1 - \eta(x) = \exp\left(-\frac{A}{V} w_0 - \frac{A}{V} w_1 x\right) \\ = \exp\left(-\frac{A}{V} w_0\right) \exp\left(-\frac{A}{V} w_1 x\right) \quad (8)$$

If the linear form of $w(x)$ is substituted into White's equation (equation 2) and integrated using an exponential particle-size distribution, we obtain the following correlating expression for total collection efficiency η_T :

$$1 - \eta_T = \frac{B \exp\left(-\frac{A}{V} w_0\right)}{B + w_1 \frac{A}{V}} \quad (9)$$

The new performance model has four primary features:

- (1) The Deutsch equation is used as it should be used - for a given particle size.
- (2) Migration velocity is characterized by two parameters, w_0 and w_1 , which are functions of the coal type and can be determined experimentally.
- (3) Inlet particle-size distribution is characterized by a single parameter, B , which is a function of the boiler type.
- (4) Overall efficiency is analytically expressed, and a closed form solution is possible.

Case Study

Particulate control costs for an 800-MW coal-fired boiler using a hot-side ESP and a fabric filter are examined in this case study. Also, the cost of selecting an improperly sized control device is discussed. The basic parameters for the case study are:

Unit size - 800 MW

Heat rate - 8000 Btu/kWh

Unit type - Pulverized coal-suspension fired

Coal type - Southwest subbituminous

Heating value - 10,000 Btu/lb

Ash content - 10%

Sulfur content - 0.8%

Emission limit - BACT of 0.03 lb/MBtu

Required particulate removal - 99/65%

Controlled emission rate - 216 lbs/hr

Hot-side ESP. Figure 5 illustrates the migration velocity as a function of particle size for a typical high-resistivity ash in a hot-side ESP. Using $w_0 = 0.02$ m/sec and $w_1 = 0.013$ m/sec from figure 5 in equation 9 reveals that an A/V of 478 ft²/1000 ACFM will provide the required 99.65 percent particle removal. This is equivalent to an average "effective" migration velocity for the entire range of particle sizes of 6 cm/sec, which is typical (5) of that reported for high-resistivity ash in a hot-side ESP.

A hot-side electrostatic precipitator operating at a temperature of 700°F in this case must treat 3,547,000 actual cubic feet per minute (ACFM) of flue gas. The ESP collecting plate area is therefore 1.7 million square feet.

The estimated turnkey capital cost for the ESP is summarized in Table 1.

The cost estimates are for an ESP delivered in late 1976. If the same system were ordered today for installation in 1981, vendor quotes would be higher to reflect almost two years of known cost inflation plus three years of estimated inflation. Also, if performance penalties are severe, the cost estimate will be higher to allow for a more conservative design and for the installation of additional collector area, if required.

Table 2 summarizes the estimated annual costs of the ESP assuming a capacity factor of 65 percent.

Table 1. Electrostatic precipitator turnkey capital cost estimate (basis: last quarter 1976 costs and dollars)

Cost item	Cost (millions of dollars)
ESP device	\$12.7
Ducting	2.8
Ash handling	2.7
Total equipment cost	\$18.2
Ash pond	3.8
Total direct cost	\$22.0
Indirect costs	8.0
Contingency and fee	7.8
Total capital investment	\$37.8
Capital investment per kW	\$47.25

Table 2. Electrostatic precipitator annual costs

<u>Operating and maintenance (O&M)</u>	
Labor and supervision	\$ 50,000
Maintenance and supplies	2,000,000
Overhead	1,040,000
Ash disposal	200,000
Electricity @ 25 mill. /kWh	<u>1,140,000</u>
Subtotal O&M costs	\$4,430,000 = 0.97 mills/kWh
<u>Fixed Costs</u>	
Insurance, depreciation, taxes	\$3,642,000
Capital cost	<u>3,400,000</u>
Subtotal fixed costs	\$7,042,000 = 1.55 mills/kWh
TOTAL ANNUAL COST	\$11,472,000 = 2.52 mills/kWh

Fabric Filter. A fabric filter in this case is assumed to operate at 346° F and to treat 2,446,000 ACFM of gas. An air-to-cloth ratio of 2 is typical of many fabric filters designed for utility boilers and in this case results in a filter area of 1,223,000 square feet. A design pressure drop of 4.5 inches of water is used to calculate operating electricity costs. If the pressure drop cannot be maintained at this level in practice, operating electricity costs will increase proportionately.

The estimated turnkey capital costs for the fabric filter are shown in Table 3. These costs, like the ESP capital costs, are for a fabric filter delivered in late 1976 and are subject to the same inflation rates.

Table 4 summarizes the fabric filter's estimated annual costs based on a 65 percent capacity factor. In this case, annual costs for a fabric filter are less than those for a hot-side ESP. This may not be true, however, for all applications where

low-sulfur coal is burned. Each application must be evaluated separately. Still, these cost estimates do support the trend shown by some utilities toward the use of fabric filters. It should be noted that this case study does not consider the need for a flue gas desulfurization (FGD) system for sulfur dioxide control. If applicable SO₂ emission limits require the use of an FGD system, the particulate-collection capabilities of the FGD scrubber should be considered. A detailed performance and cost study may well reveal that the particulate control strategy having the lowest annual cost involves using a medium-efficiency ESP followed by a wet scrubber combining FGD and particulate control.

Fabric filters usually meet or exceed the particulate-removal requirements specified in the design, but often at the cost of unexpectedly high pressure drops. Corrective action to lower the pressure drop includes installing additional modules to lower the air-to-cloth ratio, using a different fabric type, and increasing the frequency of bag cleaning.

Table 3. Fabric filter capital cost estimates (basis: last quarter 1976 costs and dollars)

Cost item	Cost (millions of dollars)
Fabric filter device	\$13.1
Ducting	0.8
Ash handling	0.5
Total equipment cost	\$16.4
Ash pond	3.8
Total direct costs	\$20.2
Indirect costs	6.8
Contingency and fee	7.0
Total capital investment	\$34.0
Capital investment per kW	\$42.50

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Table 4. Fabric filter annual costs

<u>Operating and maintenance (O&M)</u>	
Labor and supervision	\$ 50,000
Maintenance and supplies	1,000,000
Overhead	530,000
Ash disposal	200,000
Electricity	525,000
Subtotal O&M costs	\$2,305,000 = 0.51 mills/kWh
<u>Fixed costs</u>	
Depreciation, taxes, insurance	\$3,270,000
Capital cost	3,060,000
Subtotal fixed costs	\$6,330,000 = 1.39 mills/kWh
TOTAL ANNUAL COST	\$8,635,000 = 1.90 mills/kWh

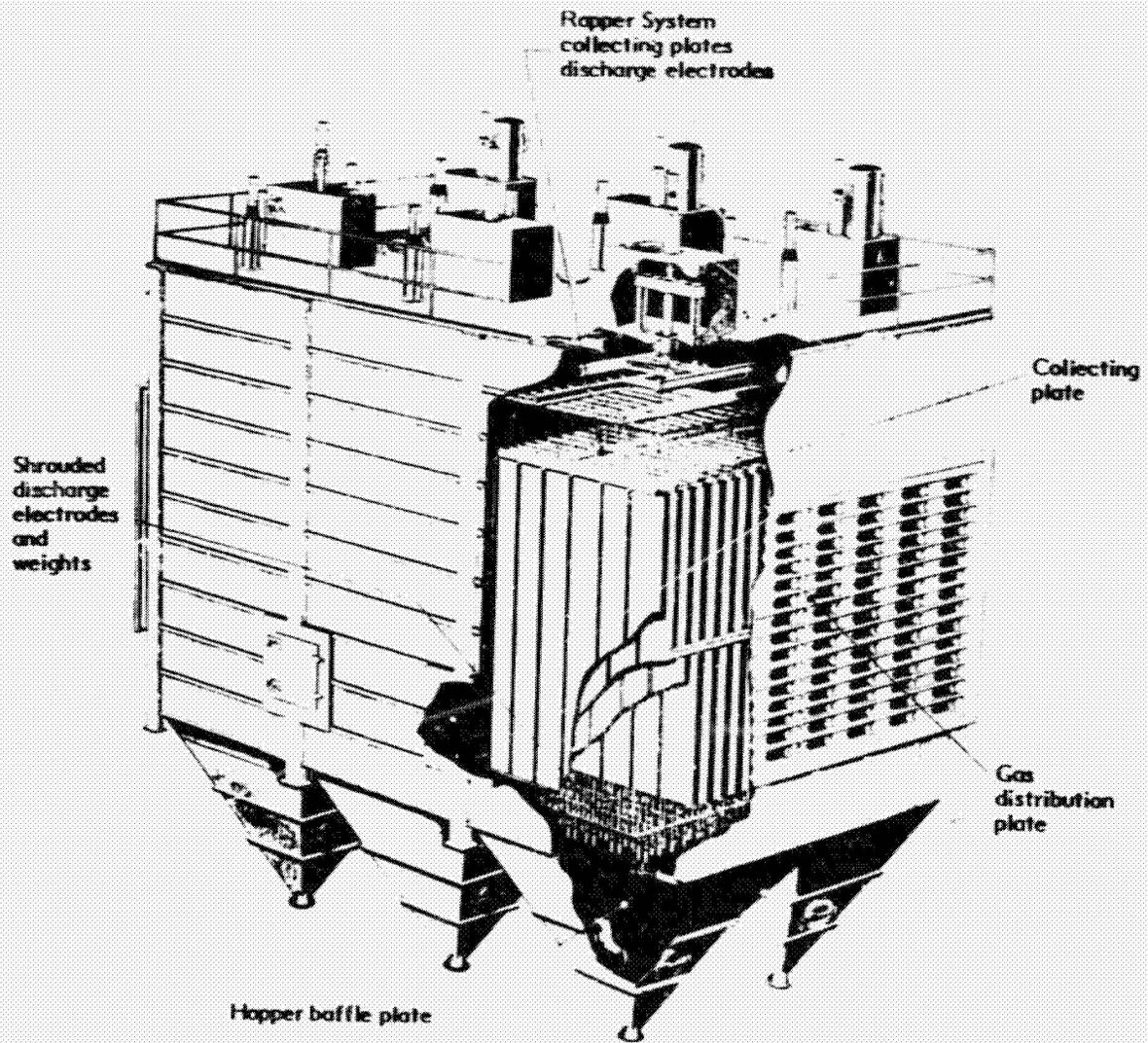
If an ESP fails to meet the particulate-removal requirements, either the average effective migration velocity or specific collector area must be increased, or a coal of lower ash content must be used. The migration velocity can be increased by using a coal with a lower ash resistivity or by conditioning the gas to lower the resistivity. The specific collector area can be increased either by retrofitting increased collector area or by derating the boiler to reduce the gas flow rate. All these options are expensive and must be evaluated for a specific site to determine which is most cost effective.

Figure 6 illustrates the effect that an improperly sized ESP can have on the cost of generating electricity. At the design point, net generating cost exclusive of fuel is 26 mills/kWh. The right side of the curve illustrates the effect on net generating cost of selecting an ESP that is larger than required, while the left side of the curve illustrates the effect of selecting one that is smaller than required (so that the boiler must be derated to achieve emission compliance). The dashed lines represent the probable range of costs if additional collector area is retrofitted. Retrofitting, however, requires time; and the boiler must operate in a derated mode for a number of months until retrofit is completed.

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3. Edgar, T.F.; Cukor; and L. Smith, "A Simple Correlating Function for Analysis of ESP Performance in Coal-Fired Power Plants," Paper No. 78-74.6, presented at the Annual Meeting of Air Pollution Control Association, Houston, Texas, June 1978.
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Figure 1
ELECTROSTATIC PRECIPITATOR



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Figure 2

TYPICAL COAL ASH RESISTIVITY AS A FUNCTION OF TEMPERATURE

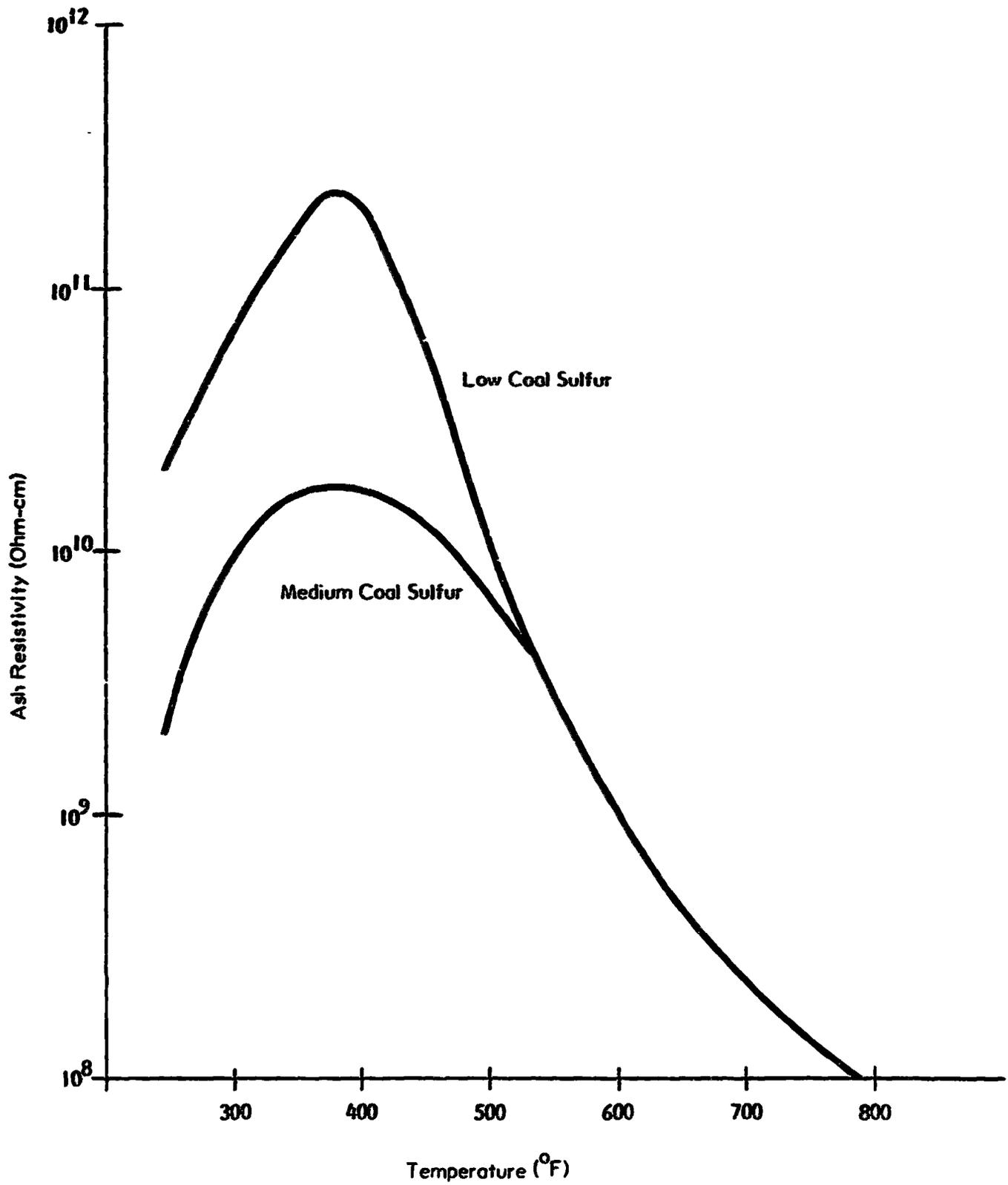


Figure 3
DESIGN PARAMETERS FOR HOT-SIDE ESP AS REPORTED TO FPC

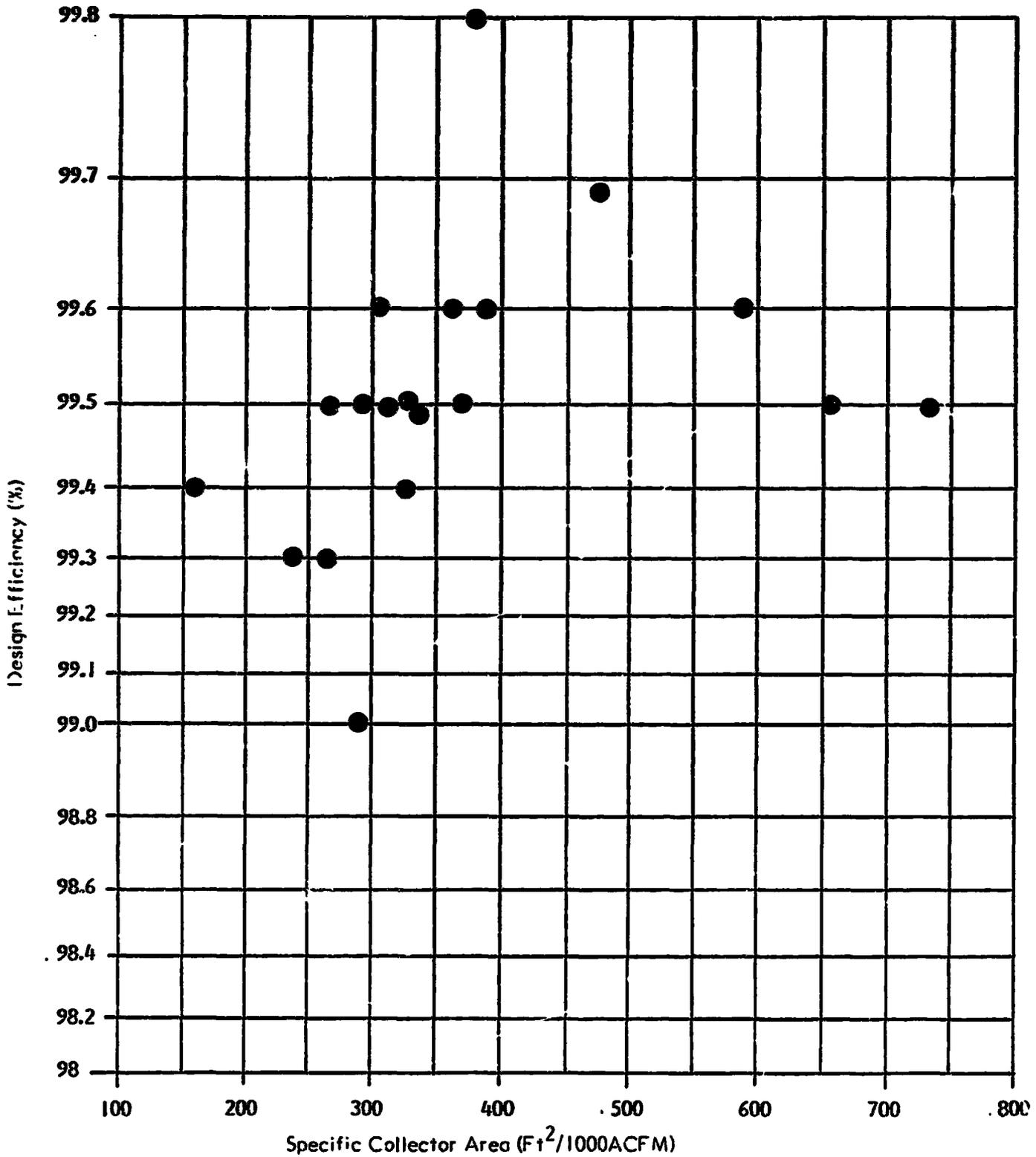


Figure 4
FABRIC FILTER MODULE

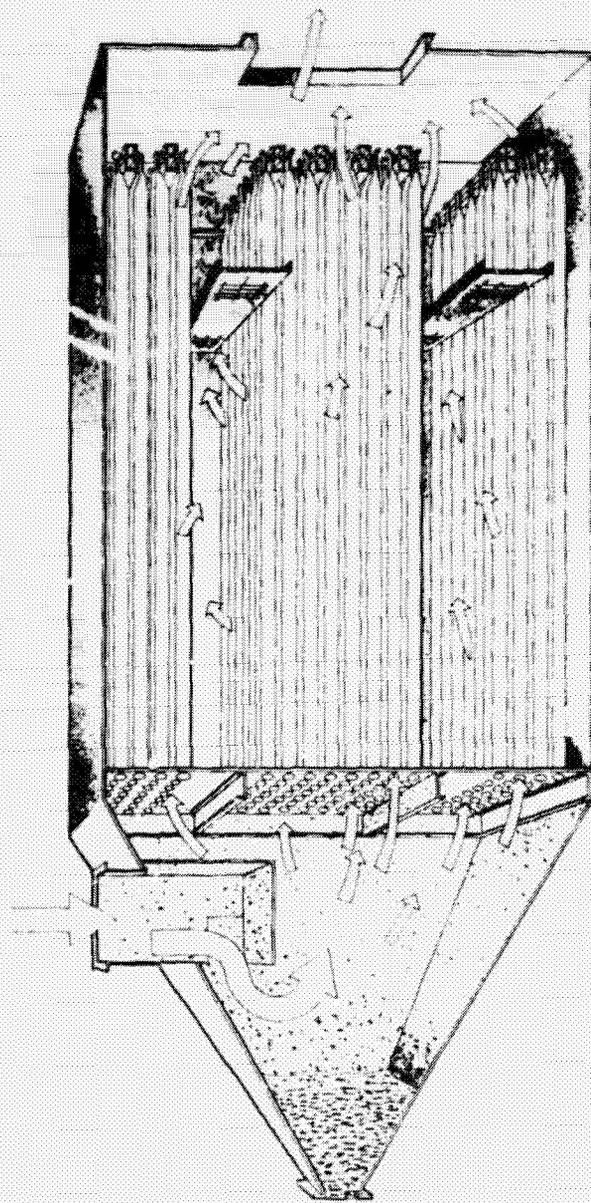


Figure 5

TYPICAL MIGRATION VELOCITY AS A FUNCTION OF PARTICLE SIZE FOR A HIGH RESISTIVITY ASH IN A HOT-SIDE ESP

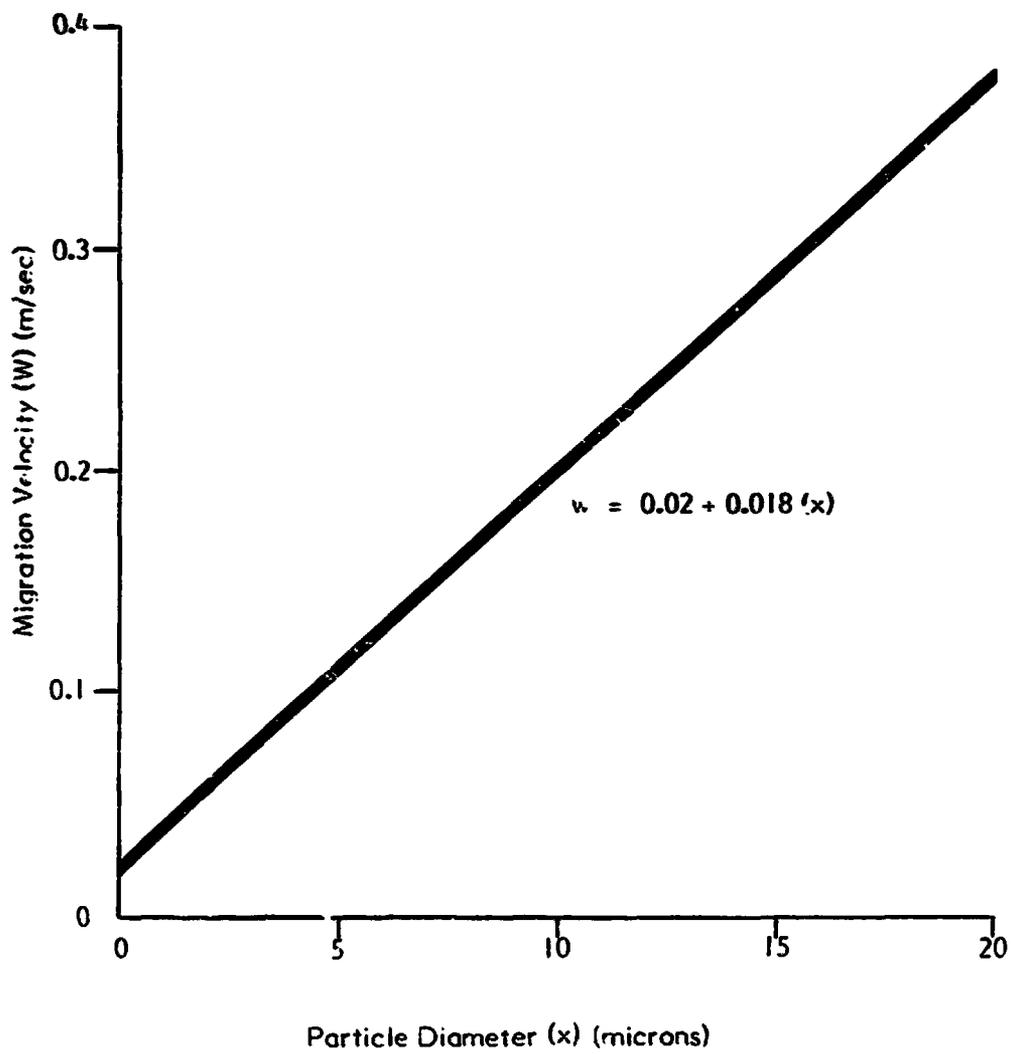
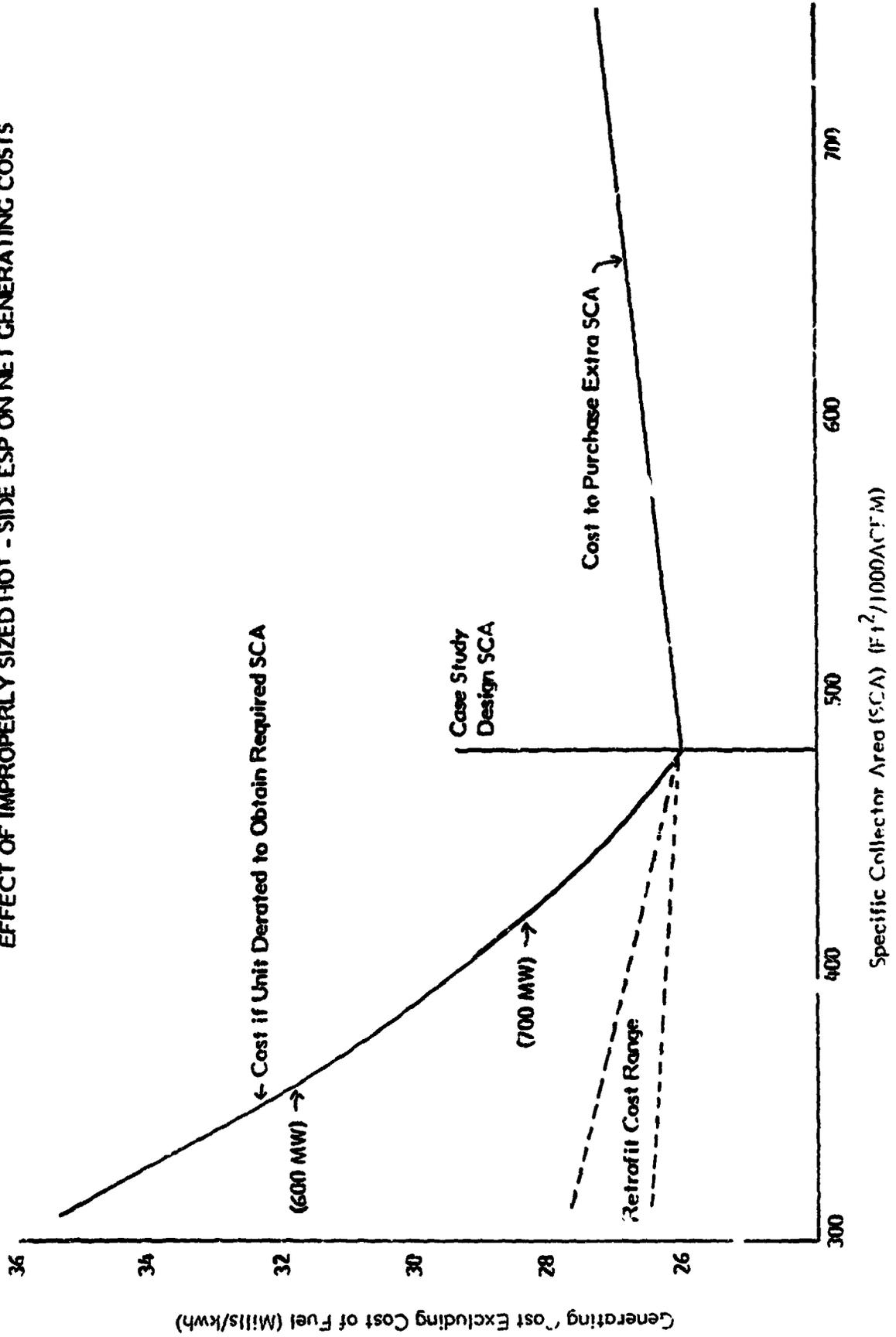


Figure 6
EFFECT OF IMPROPERLY SIZED HOT - SIDE ESP ON NET GENERATING COSTS



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SESSION VI: AIR POLLUTION CONTROL AND COAL TECHNOLOGY

Session Cochairmen: Steven Reznick (EPA),
Richard Flagan (Caltech)

Speakers: Don Teixeira (EPRI)
Frank Princiotta (EPA)
David Ensor (MRI)
Peter C. : (Teknekron, Inc.)

OPEN DISCUSSION BY ATTENDEES

STEVEN REZNEK:

In the summary we said that the three major classical pollutants from coal combustion are so called nitrogen oxides NO_x , sulphur dioxide and total suspended particulate. We indicated that without a chemical add-on for NO_x you could go from 700 ppm down to about 120 ppm; with a chemical system which is not as well demonstrated, you could reduce that 150 down to about half. Using sulphur dioxide, we are talking about chemical control particularly for the kinds of fuels that would be applicable for California, we can achieve a 90% reduction. We are suggesting that the total suspended particulate go to 99.5% reduction. In all probability, we will see a new technology which has not been used in this industry too widely, but which will probably be developed, called fabric filters on large vacuum cleaners. We've heard a great deal about costs or mills per kilowatt hours and capital costs. When you add it up, particulate NO_x control sulphur dioxide control, elimination discharge of heat and water pollution control, depending on where the new standards from EPA and where the relative standards that will be applicable in California come from we are talking of a cost for pollution control for generating new electricity of the order of 30% of the total price.

OK and with that I'll open it for questions. You can address your questions either to me or to any of the panel members the names are as they appear in the program with exception of Dr. David Ensor who spoke first on particulate control.

THOMAS AUSTIN:

I'm with the Air Resources Board. I have a question for Don Teixeira but first of all I have a comment on something Frank Princiotta mentioned.

He talked about the existence of some kind of a fundamental law which requires that things get more expensive as you learn more. One of the things that strikes me as being relevant here is that in 1973 the Environmental Protection Agency was being told by the auto manufacturers that the use of catalysts in the mid 1970s would result in a catastrophe for the industry. The cost estimates were about \$500 per car for the systems. Standards lower than EPA was talking about are now being met in California and the average cost, with which I think most of the US manufacturers would agree, is running about \$250 per car. While it may have happened on wet scrubbers, I don't think there is any fundamental law. I think that we are talking about some of the other technologies for stationary sources, such as ammonia injection, particularly the catalytic type and that we may see some substantial reductions over the next few years.

I also want to point out that, as I am sure Mr. Princiotta knows, that all of the data from the Japan scrubber experience, which shows very high reliability and very high collection efficiency, is somewhat misleading. The 95% removal efficiencies achieved by all of the power plants that Frank looked at were the result of, burning sulphur fuels for reheat. They are not scrubbing the SO₂ that is generated on a reheat. The scrubbers themselves are generally running about 9% on a continuous basis and I think that is understood by the people that have looked at them.

For Mr. Teixeira, he mentioned that the low NO_x burners that are being looked at now by industry may be available sometime in the future. I think he said that he would be very encouraged should they do better than 200 ppm when they eventually get into production. I have trouble with that, given the fact that Combustion Engineering demonstrated some years ago that it was possible to run below 200 ppm on coal if one is willing to design the boiler with a much higher furnace volume that be designed to minimize costs. As I understand it, CE ran at about 170 ppm back in the early 1970's running at around 250 megawatts. They did that by using approximately a 500 megawatt furnace volume. I would like Mr. Teixeira to comment on that because if we are talking about some fairly expensive systems to control, I am wondering whether we shouldn't also be considering much larger furnace volumes.

DON TEIXEIRA

I think that if you look at the cost of installing a boiler these days and were talking about derating the unit, that is what you're saying here.

THOMAS AUSTIN:

I'm not talking about derating the unit, I'm talking about designing a power plant, and you put in 500 megawatt generating capacity, the only thing that is derated at all is the furnace itself. It is designed at a lower maximum output than it could run at.

DON TEIXEIRA

A boiler today is costing, I would guess probably on the order of \$40 to \$50 per kilowatt - capital cost only. For installed cost you can effectively double that. So if you are going to double the size of the boiler to achieve low NO_x you are

talking the same magnitude of dollars as a catalytic NO_x system. It is not \$5 to \$10 a kilowatt as you would have in a low NO_x combustor system as I discussed with the B & W approach. That is a relatively minor change to the existing boiler system. Massive changes in the furnace size are very expensive and could lead to costs comparable to the catalytic ammonia systems.

FRANK PRINCIOTTA

I want to make a comment. I feel challenged that my new law of nature is not believed. My personal feeling is that if you substract out, as best you can the automobile manufacturer clearly had an ax to grind. I think you'd find, and I'm familiar with the catalyst situation, that some of us who knew a little bit about catalysts back 5 to 10 years ago, were not quoting those \$500 for auto numbers. If you look at the history of gasifications liquefaction, for example, you'll find that instead of the \$1 per million BTU gas, we are now talking about 4 and 5 and even higher numbers, so I think that it is a fairly valid law.

THOMAS AUSTIN

I think that you will find that EPA was wrong too. EPA was talking about 1973 dollar costs of around \$200 and \$300 per car and the 1978 dollars costs are approximately that.

ART FRIEBER

I'm with the US Navy. I would like to address my question to Dr. Cukor. In the Navy we are concerned with mixing fuel from the point of view of getting the cheapest available and the most effective. I would like to know if we have any experience in operational effectiveness with the use of precipitators and/or bag house filters handling the gas effluents for mixtures of coal and wood waste, with percentages from 0 to 100 percent of the wood waste. This might be a rare question but I am curious about an answer.

PETER CURGER

It is very interesting that you should ask the question, because a gentleman from the California Energy Commission asked me that very question this morning, and I'm not familiar with specifics. I do know that there has been a considerable amount of wood used for power generation in the State of Vermont and that the public utilities there, I'm sure, have data. Also a number of paper product companies, forest product companies in Northern California and Oregon and Washington have, for many years, been burning wood wastes to produce steam and electricity for their operations. Perhaps one of them is represented here and could discuss the results. I know of several that have Weyerhaeuser among them.

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FRANK PRINCIOTTA

I hate to commit myself but there was a revision approximately a year ago to the Federal New Source Performance Standards for particulates for power plants using wood. Presumably there was some data to back it up, although that has not always happened in the federal case. There was a readjustment for wood additives to coal burning, so that I believe, somewhere we as a collective agency, have some data on it.

IKE EASTVOLD

I am representing Desert Region for the Sierra Club. I would like to get down out of the ivory tower for a moment, since we are talking about some real proposals such as Edison's Vidal and DWR's desert proposal. The only familiarity we have anywhere close to the California Desert with a coal-fired plant is the horrible example of the Mojave Plant.

What I would like the members of the panel to do, just very briefly, is to consider the Mojave scenario, I believe is a 1580 megawatt plant consuming 5 million tons of black mesa coal a year. It has a 10.9 percent ash content and a .40 sulphur content, with a heat content BTU per pound of 10,825. Could you take that scenario for NO_x , SO_x and particulates, comment on what you would use by way of best available control technology if that

plant were built today. What would you do differently today if that plant were built in the California Desert that was not done when it was built originally?

FRANK PRINCIOTTA

Does anyone care to comment? In fact I happened to visit the Mojave Plant a couple or three years ago and of course it does not have a flue gas desulphurization system. Fortunately one can get higher SO₂ removal efficiencies, less operating costs and generally fewer problems with low sulphur coal. Contrary to what your intuition might tell you, scrubbing low sulphur coal boilers is a lot easier in all respects than high sulphur coal facilities. Clearly a Mojave type unit could have incorporated anything from an ash scrubbing system, which can get typically in the order to 40, 50, and 60% SO₂ removal, or a limestone flue gas desulphurization system, which would be capable easily of 85 or 90% overall sulphur oxide control. I think I'll leave it to the other speakers to talk about NO_x particulate control, but clearly things could be improved there as well.

STEVEN REZNEK

Frank, when we say it's easier and cheaper to operate a low sulphur coal that is for dollar per kilowatt, not dollar per pound of sulphur removed.

FRANK PRINCIOTTA

That is correct. As far as the total impact on the cost of producing electricity, generally the impact is less on a western source than it is in the East.

DON TEIXEIRA:

I would like to add just briefly to what Frank said. I think that in terms of what has already been said this afternoon, with regard to particulate and SO₂ control - if it were deemed desirable - the kinds of controls that have been presented here and

their associated costs could be achieved. But NO_x control is one technology that high removal efficiencies are still difficult to achieve. It's not been the subject of such intense research as scrubbers and particulate control, which have been around for a fair amount of time. It is just now that those technologies that I was discussing in terms of advancements could be considered for something in the probably mid-80's. Today's NO_x technology isn't too much better than what was used back in the days of Mojave.

STEVE REZNEK

We are investing on the order of 10 million dollars a year in the demonstration of NO_x control technologies. We believe the staged combustion, such as that outlined by Mr. Teixeira is going to work and prove quite effective. One of the problems is boiler corrosion; what happens in the reduced oxygen atmosphere. We will be ready to go fairly shortly into a full scale long term demonstration to get rid of the corrosion problem. We feel a 2 or 3 year time frame for a commercial size demonstration of staged combustion modified burners will allow then a decision on whether to lower the new source performance standard.

DON TEIXEIRA:

Actually, Steve, I might point out that the recently proposed new source performance standard will also tighten down on nitrogen oxide. This implies then that there have been advances in nitrogen dioxide control technology. I think the current level of .7 pounds per million BTU will be reduced probably to .5 or .6 depending upon the coal type. It is dependent somewhat on the sodium content and how this might lead to a potential corrosion problem. I would guess that the Mojave Unit is probably designed for around the .7 number.

BENJAMIN LINSKY

I'm here by accident because I happened to be in town attending an American Industrial Hygiene Assn. Conference and I heard about the conference.

BENJAMIN LINSKY

I am a professor at West Virginia University in Air Pollution Control Engineering. I just retired and am adjunct professor and consultant. I have a strong feeling for California because I started the Bay Area Air Pollution Control District.

I think my major point as a former Californian with strong feeling is that we are shooting at the wrong kinds of targets. You are shooting at traditional boiler design and a traditional collector design which is totally inaccurate. It is imperative that this be drawn sharply to the attention of everyone here.

Number one, you should be, I think, talking about combined collector systems. This is not new to the electric utility industry. They used to talk about multiple cyclones, followed by or preceded by, electrostatic precipitators. In the carbon black industry they now use electrostatic precipitators for agglomeration, plus collection and bag house. There is another bag house in series, not for if a bag will break, but for when a bag will break. Everyone here knows that this happens. Those who are technologists and scientists know this even better. This is the area and this is the range of collection equipment that needs to be taken care of with respect, to sulphur oxides and any additives for the particulates which include not only the alumina and other fly ash components that were mentioned but also something that seemed to escape and that was carbon. That carbon is frequently polynuclear hydrocarbons, sometimes called carcinogenic. This is my major statement and my question is of two kinds. First, you gave a price of 30% added to the cost of electricity, but you added in the cost for treatment of hot water. What would the air pollution added price be, based on just the technologies you have talked about?

FRANK PRINCIOTTA

I believe that an extra 5% for the cooling tower is added, so that it is about 25%. It's very dependent, as Peter pointed out, for particulate control, which is not as expensive as sulphur dioxide, on the exact nature of the final emission regulation for sulphur dioxide.

BENJAMIN LINSKY

The 25% that you speak about is the highest figure I have ever heard, but even that is added to the price at the factory. It is not the delivered cost.

FRANK PRINCIOTTA

That's right, busbar.

BENJAMIN LINSKY

It's busbar cost, somehow I don't even buy an auto at the factory price.

FRANK PRINCIOTTA

The general factor is a half for the price of new electricity to the consumer and of course that price will be rolled in against the rate structure. So you won't see it for the first couple of plants and then it will grow as time goes on.

BENJAMIN LINSKY

What is the delivery cost? **REPRODUCIBILITY OF THE ORIGINAL PAGE IS POOR**

FRANK PRINCIOTTA

For new electricity, half of the 25%.

BENJAMIN LINSKY

That was not made clear here before, you don't mind my bringing it out?

FRANK PRINCIOTTA

No, not at all.

BENJAMIN LINSKY

I have a question for the gentleman from EPRI who was talking about the difficulty of translating Japanese costs, especially operating and maintenance costs. I would guess that you have the capability, or can employ the capability, of getting translations in terms of man hours, if you are looking at different kinds of wages and

that sort of thing. I believe that has been done in some of the work that we have done with the USSR. It is done in terms of manhours and then back into dollars, rubbles, yen etc., and back to dollars. I'm amazed that you have that difficulty in arriving at information about these fully-functioning plants, that have been functioning for many years. It is therefore called unreliable, while the information about it is being taken down on a transistor tape recorder that was probably made in Japan.

DON TEIXEIRA:

Number one, the systems (catalytic NO_x) have not been fully operational for years, they are at the 1 megawatt pilot plant scale, and have been for about the last 2 years. I can operate a calculator as well as the next person and I can convert from yen to dollars and we do not have some statistics on yen to labor productivity. Unfortunately, it is still quite that simple because there are differences in philosophy and this philosophy extends into the industrial area, the way the power plants operate and just deal with their product: electricity. One simply cannot take these numbers and arbitrarily say that this box which is so many cubic feet in a Japanese installation is that same number of cubic feet in an American installation. We are spending a considerable amount of money right at this moment to try to get these costs converted.

A.J. WILSON

I'm with the South Coast Air Quality Management District. We are a four-county agency covering Los Angeles, Riverside, San Bernardino and Orange Counties. The general consensus I felt was, because of a general conference like this, you have to rush the speakers somewhat. Therefore I'd like to invite the panel that you have assembled this afternoon to speak to our organization and any other people in the audience who would like to have a more

intensive or detailed understanding of what the speakers actually presented rather than feel the pressure of time. We have a facility about 10 miles from here and if we could arrange this, I would appreciate it. Thank you.

UNIDENTIFIED ATTENDEE

I'm with the Energy Source Journal, also from the University of Southern California. I have two general questions to the panel. The first question is related to quality control assurance of the control technology. We know that one can always build a boiler for certain types of coal, but we know the types of coal could change drastically. Even within one seam the content is quite different. For example, the sulphur types, the nitrogen types, the basic nitrogen or the neutronitrogen, and the minerals are also quite different. I'd like to know what assurance we will have resulting from different types of coal feeds, that the control technology that has been developed will be able to handle the different emission levels. The second question is concerning the carbon type of particulates. I guess we cannot rule out that carbon particulates are there, and especially for nitrogen bearing materials like polynuclear hydrocarbons, those particulates are very health hazardous to us. They are not only having organic or carcinogenic but maybe even neutrogenic effects. Is there any control technology at this time to handle such submicron size, maybe less than 2 tenths maybe even less than .2 micron submicron size? Those particulates probably have nitrogen in them and it causes concern. And this is a general type of question when they are not minerals or ash, and they are not with silica.

STEVE REZNEK

Regarding the other pollutants, which are not the ones we have been talking about, the organics the carcinogenic material, that was associated with coal, the answer is, there is a good deal of work going on trying to assess these emission factors. An interesting experiment was done out here in Berkeley, which found that in terms of the Ames Test which is a mutagen in a bacterial system, the activity in producing those revertant mutations was associated

with very fine particles, rather than large particles. That tends to suggest that its either a metal condensate or an organic condensate that you are seeing in that very small size range. These control systems, particularly scrubbers for sulphur dioxide, will, in lowering the temperature, remove some of this material. At this point its very hard for any one to quantify that, even say benzoapyrene, let alone the carcinogenic value. Nevertheless, these control systems do achieve a great deal of control. If you are at a 99.5 percent removal with a good bag house and its dips at this small particle range, it will dip to 99% so it's not dipping down to zero by any stretch of the imagination. We are working very hard trying to quantify some of those things, but they are very hard measurements to make. They are very hard things to get a handle on.

DON TEIXEIRA:

Before we leave that I have a slide that perhaps can address some of your concerns here. It plots the fractional collection efficiency - meaning the removal efficiencies of size of different particulates - for both bag houses and precipitators based on some data that was obtained within the last couple of years. What you see is that the size range which is of greatest concern from a visibility standpoint and from a health standpoint, is an area that has a very high collection efficiency in a fabric filter. As Steve has pointed out quite accurately, a number of people are concerned about the material in the 0.01 to 1 micron size range. The fabric filter is quite efficient in this range and for that reason one would also expect that it is an efficient collector of other heavy metals or some such compound that happens to persist in that particular size range: the bag house doesn't care if it's a piece of silica or whatever - it is a particle and it is collectable.

TEH FU YEN:

The Asian type particulates may be less than .02 micron size and even smaller than those. Those are not organometallics or even heavy metals because those you can precipitate down. If you have something which has different electric properties and there is no way that you can use the conventional system to clean them, then this would be of some concern at this time.

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STEVEN REZNEK:

As you get below a certain size like .2 microns collection efficiency of any of these devices electric or bag, what goes up doesn't get worse, it gets better.

REBECCA SPARLING

I'm representing the American Assn. of University Women. Members of this panel, as well as ones yesterday, continue to respond to the Japanese results in cleaning up the emissions. I am quite curious. I did not see any mention of what type of coal the Japanese were using. Do they use a coal similar to our western coals with fairly high ash and low sulphur?

FRANK PRINCIOTTA

I think that I can answer that. Generally it is a confused situation. As I recall three of the five units in Japan have scrubbers on them and burn a moderately high sulphur coal. It is around 2 percent, which is substantially higher in sulphur than the western coals. They do have quite a bit in the way of ash though. As I recall the ash content is somewhere between 15 and 20 percent, which again is substantially higher than western coal. I would say relative to a western coal, as far as scrubbing is concerned, Japanese coals are more difficult than the coals in this part of the country.

REBECCA SPARLING

But, in view of the fact that several people also mentioned, and some of the slides showed, the marked effect of the changes in types of coal, then do you think that we can extrapolate not only from the 1 to 1000 megawatt, but also from the Japanese coal to the Utah coals.

FRANK PRINCIOTTA

I. the case of process, technology is a little bit different. In the case of flue gas desulphurization, I personally would feel very confident in extrapolating the Japanese results to western coal. That is the point to remember. The other gentlemen might want to comment.

STEVE REZNEK

On the coals, Frank, one of the plants, ISOGO Power Station using a .6% sulfur coal that comes from the island of Hokkaido. It's about 14% ash content and is within the range of western coals.

DON TEIXEIRA:

Very briefly the slide shows the removal efficiency as a function of particle diameter and the lower set of curves there are for the bag house at 2 different operating conditions. As you can see, for discussion purposes the curves are essentially flat as compared to precipitators so that in the size range producing visible emissions.

SESSION VII

COAL TECHNOLOGY — DIRECT FIRING

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John G. Kau

Ultrasystems, Inc.
Irvine, California

ABSTRACT

Economic considerations involved in fuel conversion such as from oil and/or gas firing to coal include investment costs for new facilities and equipment (including air pollution control equipment), operation and maintenance costs, and purchased fuel costs. This paper presents an analytical approach to assessing the cost effectiveness of fuel conversion in terms of the annual net cost of conversion, the equivalent annual number of barrels of oil saved, and the internal rate of return of the conversion investment. Illustrative numerical examples are presented for typical utility boilers and industrial boiler facilities. A further consideration addressed deals with the impacts of these costs on the overall financial structure of the firm and the ability of the firm to raise the necessary investment capital.

I. OVERVIEW OF COAL CONVERSION ACTIVITIES

By coal conversion in this paper we mean the switching from either oil and/or gas as the primary fuel(s) to coal as the primary fuel in a combustor (boiler, burner, furnace or kiln). Historically, fuel switching has generally tended to be in the other direction, namely, oil/gas conversion. For example, during the late 1960's and early 1970's, while coal-fired powerplants were being converted to oil, utilities were also building new plants to burn oil. Initially, utilities converted to oil for economic reasons; however, more recently, the principal reason for converting to oil has been the requirement to meet strict sulfur emission regulations which the utilities were unable to do using coal. Most of these conversions took place on the East Coast at plants with easy access to ocean and river barge transport.

In 1970, it is estimated (Ref. 1) that only 40 new boiler orders provided for coal-firing capability. In 1974, however, in response to the natural gas shortages and increased price of oil, 97 of new boiler orders provided for coal-firing capability. Consequently, we see a trend occurring back to coal conversion. It is noteworthy that, according to Reference 2, about 80% of the boilers which were converted from coal to oil can, in time, be re-converted to coal.

The current impetus for coal conversion is caused by the legislative requirements of the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (Public Law 93-319), as amended by the Energy Policy and Conservation Act (EPCA) of 1975 (Public Law 94-163). It is intended that ESECA, by providing the Department of Energy (DOE) with the authority to require the use of coal by existing and future electric utility powerplants and other major fuel burning installations (MFBI's), will result in a significant decrease in the use of petroleum and natural gas and an increase in the use of our most abundant domestic energy resource.

Collectively, ESECA and EPCA provide DOE with the statutory authority to issue a Prohibition Order to an existing facility for the purpose of prohibiting the further use of oil and/or gas as the primary fuel(s). Before such an order can be issued, DOE must determine that the powerplant or MFBI possessed the necessary equipment and capability to burn coal on June 22, 1974, or acquired it thereafter. DOE must assess the existence of certain necessary coal handling facilities and appurtenances such as adequate facilities for the storage of coal, and equipment such as a boiler, unloaders, conveyors, crushers, pulverizers, scales, burners, soot blowers, and special coal burning instrumentation and controls. In addition, DOE must also find that:

- (1) the burning of coal at the facility is practicable and consistent with the purposes of ESECA;
- (2) coal and coal transportation facilities will be available for the period the order is in effect; and
- (3) in the case of a powerplant, the order will not impair the reliability of service in the area served by the converting powerplant.

Prohibition Orders were issued in 1975 affecting 74 powerplant units and were issued in 1977 affecting 18 powerplant units and 27 MFBI combustors.

DOE is also provided with the statutory authority to require powerplants or MFBI's in the early planning process to be designed and constructed so as to be capable of using coal as the primary energy source. This is accomplished through the issuance of a Construction Order. No such order may be issued if DOE finds that (a) in the case of a powerplant, such order is likely to impair the reliability or adequacy of service, or (b) an adequate and reliable supply of coal is not expected to be available. Furthermore, in considering the desirability of issuing such an order, DOE must consider the existence and effects of any contractual commitment for the construction of such facility, and the ability of the owner to recover any capital investment made as the result of a Construction Order. Orders of this type were issued in 1975 affecting 74 new powerplants and were issued in 1977 affecting 18 new powerplants and 27 new MFBI combustors.

II. CONSIDERATIONS AND FACTORS IN COAL
CONVERSION INVESTMENT

Major considerations of significance in assessing the willingness and/or overall acceptance of coal conversion include the following:

- (1) the difficulties industry will experience with environmental and facility siting regulatory problems
- (2) the aversion industry has to using coal

due to the difficulties of handling coal at the plant, the extra personnel required, etc.

- (3) the higher rate of return some firms require on a discretionary investment (assuming no DOE order is issued) - especially one which may neither enhance output nor protect production.
- (4) the added risks associated with reliability of coal supply to the plant.

Of particular importance are those factors which have a direct effect on costs such as:

- (1) combustor size affects costs since costs of coal equipment as well as pollution control equipment are characterized by economies of scale
- (2) capacity utilization determines how quickly capital costs are recovered as the result of fuel price savings
- (3) coal capability is a factor because, if the unit was designed originally to fire coal, the capital costs of conversion will, most likely, be less than the cost differential between a new gas/oil-firing and a new coal-firing unit
- (4) remaining useful life of facility determines the period of time over which the conversion investment can be amortized and thus affects the rate of return on the investment
- (5) regional location affects costs primarily through delivered fuel prices
- (6) environmental controls imposed through state regulations and Federal New Source Performance Standards affect the costs of the pollution control equipment necessary, which in many cases is the most significant capital cost
- (7) new versus existing units for conversion involves the tradeoff between new capital equipment and thus longer amortization period versus modification of used and existing units with perhaps a shorter amortization period
- (8) fuel type as determined by sulfur content required, percent ash required, etc. and the means transportation affects the corresponding fuel price differential.

III. BREAKEVEN FORMULATIONS FOR COAL CONVERSION INVESTMENT

In terms of analyzing on an annual basis the investment by a company in coal conversion, there are three basic quantities to be considered, namely:

- (1) annualized investment cost, which is defined to be

$$\left(\frac{\text{Total investment}}{\text{cost}} \right) \left(\frac{\text{Capital recovery}}{\text{factor or fixed}} \right) \left(\frac{\text{charge rate}}{\text{charge rate}} \right) ;$$

- (2) annual fuel cost differential, which is defined to be

$$\left(\frac{\text{Fuel cost}}{\text{differential}} \right) \left(\frac{\text{Heat rate}}{\text{in BTU's/}} \right) \left(\frac{\text{Size}}{\text{in kw}} \right) \left(\frac{\text{760 hrs}}{\text{per year}} \right)$$

$$\times \left(\frac{\text{760 hrs}}{\text{per year}} \right) \left(\frac{\text{Average}}{\text{capacity}} \right) \left(\frac{\text{factor}}{\text{factor}} \right) ;$$

- (3) annual operation and maintenance cost differential, which is defined to be

$$\left(\frac{\text{O\&M cost}}{\text{differential}} \right) \left(\frac{\text{Size}}{\text{in kw}} \right) \left(\frac{\text{760 hrs}}{\text{per year}} \right) \times \left(\frac{\text{Average}}{\text{capacity}} \right) \left(\frac{\text{factor}}{\text{factor}} \right) .$$

In the formulation of the annualized investment cost, multiplying the total investment cost by either the capital recovery factor, defined to be

$$\frac{i(1+i)^N}{(1+i)^N - 1}$$

where *i* is the annual discount rate which reflects the worth of capital and *N* is the number of years over which the investment is amortized, or by the annual fixed (or levelized charge) rate has the effect of amortizing the investment over a specified period of time (generally the remaining useful life of the facility). Typically, the choice of the discount rate is based on the weighted cost of capital as determined according to the sources of capital. For example, consider the following computation:

Capital Source	Percent of Total Capitalization	Capital Cost (%)	Weighted Cost (%)
Mortgage Bonds	50	8.1	4.05
Preferred Stock	15	8.3	1.25
Common Equity	35	15	5.25
			10.55

Therefore, the discount rate used would be 10.55% based on a weighted average cost of new capital.

Another approach would be to use a fixed (or levelized) charge rate as is done by utility companies to compute the annualized investment cost. This rate is chosen as a measure to describe the revenue which must be raised annually to earn a reasonable return on the capital used to purchase equipment, to amortize the equipment over its productive life and to pay requisite income taxes, property taxes and insurance. This rate depends upon the consideration of many factors including the following: the capital structure of the company; the required return on debt, common and preferred stock; the useful life of the equipment and its scrap age value, if any; the formulas used in computing actual and tax depreciation; whether tax savings from depreciation and the investment tax credit are normalized or flowed through; the effective tax rate (combined federal and state); the property taxes. Typically, fixed charge rates range from 20-40%, depending upon the relative importance of the above factors.

In order for the investment in coal conversion to breakeven the following must be true:

$$\left(\frac{\text{Annualized}}{\text{investment}} \right) \left(\frac{\text{cost}}{\text{cost}} \right) = \left(\frac{\text{Annual}}{\text{fuel cost}} \right) \left(\frac{\text{differential}}{\text{differential}} \right) - \left(\frac{\text{Annual}}{\text{O\&M cost}} \right) \left(\frac{\text{differential}}{\text{differential}} \right) .$$

The righthand side of this equation represents the net gain due to fuel price savings.

As an illustration, consider the conversion of 2 800-megawatt boilers requiring flue gas desulfurization (FGD). This conversion is estimated to take place in 1980 at a cost of \$804/kw. These boilers are assumed to be operated at 70% capacity over their remaining 20 years of useful life, and have a design heat rate when coal-fired of 9,700 BTU's/kwhr. Assuming a 11% discount rate, this implies a capital recovery factor equal to

$$\frac{(.11)(1.11)^{20}}{(1.11)^{20} - 1} = .12557$$

or, equivalently, a fixed charge rate of approximately 12.6%. Therefore,

$$\left(\frac{\text{Annualized investment}}{\text{cost}} \right) = (1,600,000 \text{ kw}) \left(\frac{\$804 \text{ per}}{\text{kw}} \right) \times (.12557) = \$12,557,564$$

$$\left(\frac{\text{Annual fuel cost differential}}{\text{differential}} \right) = \left(\frac{\text{Fuel cost differential}}{\text{in } \$/10^6 \text{ BTU's}} \right) (9,700 \text{ BTU's/kwhr}) \times \left(\frac{1,600,000 \text{ hrs}}{\text{per yr}} \right) (.70)$$

$$= (95,168,640) \left(\frac{\text{Fuel cost differential}}{\text{in } \$/10^6 \text{ BTU's}} \right)$$

$$\left(\frac{\text{Annual O\&M cost differential}}{\text{differential}} \right) = \left(\frac{\text{O\&M cost differential}}{\text{in } \$/\text{kwhr}} \right) (1,600,000) \times \left(\frac{8,760 \text{ hrs}}{\text{per hr}} \right) (.7) = (9,811,200)$$

$$\times \left(\frac{\text{O\&M cost differential}}{\text{in } \$/\text{kwhr}} \right)$$

For breakeven we must then have

$$12,557,564 = (95,168,640) \left(\frac{\text{Fuel cost differential}}{\text{in } \$/10^6 \text{ BTU's}} \right) + (9,811,200) \left(\frac{\text{O\&M cost differential}}{\text{in } \$/\text{kwhr}} \right)$$

Figure 1 provides a plot of fuel cost differential versus O&M cost differential using this linear relationship for breakeven. Assuming a 1.4 mill/kwhr O&M cost differential, this implies a fuel cost differential of approximately \$1.34 per 10⁶ BTU's. An estimated 1980 coal price (Source: Pacific Gas & Electric Co.) is \$1.49 per 10⁶ BTU's. This implies that in 1980 for breakeven the price of oil must be at least \$3.33 per 10⁶ BTU's or, approximately \$20.31 per barrel, which is comparable to DOE estimates of the 1980 range of oil prices.

IV. OVERALL METHODOLOGY FOR EVALUATION OF COAL CONVERSION ECONOMICS

In the evaluation of the overall reasonableness of coal conversion by utility companies, the Department of Energy (formerly the Federal Energy Admin-

istration) utilizes a methodology (see Refs. 7&8) which considers such factors as: boiler size, remaining useful life after conversion, operating capacity both before and after conversion, and derating (i.e., loss of power because of pollution control equipment), if any, estimated fuel prices both before and after conversion; investment costs for both air pollution control equipment and non-air pollution control equipment; O&M cost differential for both air pollution control equipment and non-air pollution control equipment; annual fixed charge rate, or cost of capital if the capital recovery factor is used to obtain the amortized investment cost; annual fuel cost differential; annual fuel consumption by type of fuel both before and after conversion; heat content in BTU's for each type of fuel consumed. These factors are used to compute overall evaluation measures such as:

- (1) equivalent annual barrels of oil saved as a result of conversion
- (2) annual cost per equivalent barrel of oil saved
- (3) change (annual cost differential) in cost per kilowatt-hour of electricity generated
- (4) rate of return both before and after taxes from the coal conversion investment.

Tables 1-3 provide an illustration of this methodology applied to the case of converting two boilers with a total 158 MW capacity currently using both natural gas and oil. Table 3 shows that for this example conversion will save approximately 1.355 million barrels of oil per year at a cost to the company of \$1.95 per barrel saved (considerably less than the price of a barrel of oil) and at an increase of 3.472 mills per kilowatt-hour generated; however, the rate of return from this particular investment is far from attractive by today's standards as is seen by the 6% before taxes and 3.2% afterwards (using straight line depreciation).

V. FINANCING CONSIDERATIONS

Assessing the overall financial impact of conversion, consideration must be given to those initial investment and annual costs which are incurred as the result of establishing a coal-burning capability. The basic investment costs will consist of those associated with the retrofit of existing and/or acquisition of new air pollution control equipment, and those associated with the acquisition of coal handling equipment and facilities. The basic annual costs will consist of fuel costs, fixed charges for such items as interest, taxes, depreciation, etc., operation and maintenance costs associated with non-air pollution control equipment. Other factors of importance would include the time required to complete conversion, the remaining useful life of the boilers which are converted, and the cost of borrowed capital.

These investment and annual cost factors affect the overall financial structure of a firm in a number of ways. This is best illustrated by examining the potential impacts on the standard financial statements of a firm given by the Balance Sheet and Income Statement. For example, the basic investment costs would affect the investments, property, plant and equipment, and long-term debt (and maybe even the preferred stock and common stock) categories. The operation and maintenance cost items could potentially affect subsequent retained earnings. Fuel costs enable the acquisition of a coal supply and

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they potentially will impact the current assets, current liabilities, and retained earnings categories. Fixed charges would potentially affect both current liabilities and retained earnings.

With regard to the Income Statement, investment costs would impact the income taxes paid based on the amount of investment tax credit claimed and, as a result, would affect the firm's net profit after taxes. Both the operation and maintenance costs and the fuel costs would impact the cost of goods sold category and, as a result, the firm's gross profit. Fixed charges would affect the operating expenses, other expenses and income taxes categories and, as a result, would also have a direct effect on the firm's net profit after taxes.

Other considerations which affect the capital aspect of a firm's financial structure are as follows:

(1) growth rate of future sales

The future growth rate of sales is a measure of the extent to which the earnings per share of a firm are likely to be magnified by leverage. In some cases, financing by debt with limited fixed charges should magnify the returns to owners of the stock. On the other hand, the common stock of a firm whose sales and earnings are growing at a favorable rate commands a high price in which case equity financing is desirable. A firm must weigh the benefits of using leverage against the opportunity of broadening its equity base when it chooses between future financing alternatives.

(2) stability of future sales

Sales stability and debt ratios are directly related. With greater stability in sales and earnings, a firm can incur the fixed charges of debt with less risk than it can when its sales and earnings are subject to periodic declines; in the latter instance it will have difficulty in meeting its obligations.

(3) competitive structure of the industry

Debt-servicing ability is dependent upon the profitability as well as the volume of sales; hence, the stability of profit margins is as important as the stability of sales. The ease with which new firms may enter the industry and the ability of competing firms to expand capacity will influence profit margins. A growth industry promises higher profit margins, but such margins are likely to narrow if the industry is one in which the number of firms can be easily increased through additional entry.

(4) asset structure of the industry

Asset structures influence the sources of financing in several ways. Firms with long-lived fixed assets use long-term mortgage debt extensively. Firms whose assets are mostly receivables and inventory whose value is dependent on the continued profitability of the individual firm (for example, those in wholesale and retail trade) rely less on long-term debt financing and more on short-term.

(5) control position and attitudes toward risk of owners and management

The management attitudes that most directly influence the choice of financing are those concerning (1) control of the enterprise and (2) risk. Large corporations whose stock is widely owned may choose additional sales of common stock because they will have little influence on the control of the company. In contrast, the owners of small firms may prefer to avoid issuing common stock in order to be assured of continued control. Because they generally have confidence in the prospects of their companies, and because they can see the large potential gains to themselves resulting from leverage, managers of such firms are often willing to incur high debt ratios.

(6) lender attitudes toward firm and industry

Regardless of management's analysis of the proper leverage factor for their firms, lenders' attitudes are frequently the most important determinant of financial structure. When management seeks to use leverage beyond norms for the industry, lenders may be unwilling to accept such debt increases. They will emphasize that excessive debt reduces the credit standing of the borrower and the credit rating of the securities previously issued.

Traditionally, corporations have had three sources of capital for investment in property, plant and equipment:

- (1) Reserves for depreciation, depletion and amortization are essentially deductions from operating income which can be used for new investment.
- (2) Long-term and short-term debt may be increased through the sale of debentures and other debt instruments.
- (3) Equity capital may be raised through the issuance of preferred or common stock.

With regard to reserves, they are generally short-term and, in many cases, not sufficient in amount. Both long- and short-term debt are constrained by the lending institutions' desired capitalization profile for a firm. For example, long-term debt for utility companies is typically on the order of 45-55 and debt greater than 55 could lead to a lowering of bond ratings. In many cases there are mortgage indenture coverage requirements in times-interest-earned before new debentures can be issued. For equity capital, preferred stock typically represents 10-15 of total capitalization and common stock 30-40 for utility companies. There are in many cases coverage requirements on both interest and dividends before new equity capital can be raised.

This discussion points out that, even though it may be technically feasible for a company to convert from using oil and/or gas to the use of coal as its primary fuel, the financial impact of the firm must be considered as well as the sources of the needed capital. The ability to attract capital is promoted by a demonstrated ability to provide investors with a fair and reasonable return on their investment, to maintain a balanced capitalization structure, and to generate a reasonable amount of capital requirements internally.

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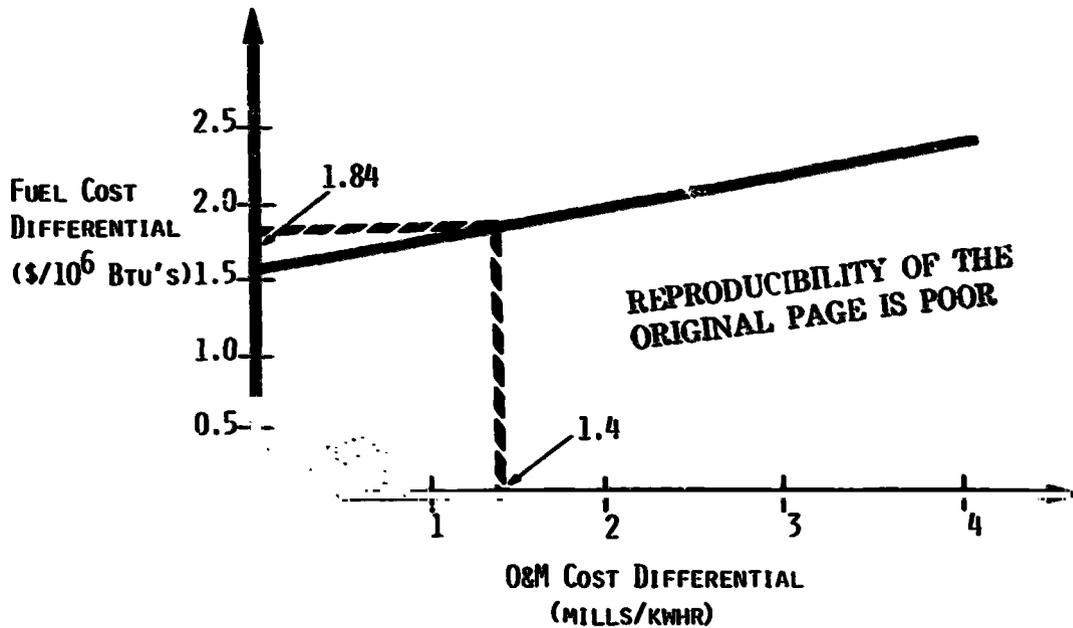


Fig. 1. Fuel Cost Differential Versus O&M Cost Differential for Breakeven

Table 1. Illustrative Site Characteristics and Fuel Prices

SITE CHARACTERISTICS

Boiler Unit	Megawatt Capacity	Remaining Life	Operating Capacity		Derating Percent
			Before	After	
Number 1	51.0	20	.550	.550	0.000
Number 2	107.0	20	.550	.550	0.000

FUEL PRICES (IN DOLLARS PER MILLION BTU'S)

	Before Conversion	After Conversion
Coal	0.0000	1.6000
Oil	1.9130	
Natural Gas	1.5500	

Table 2. Illustrative Cost Data

INVESTMENT COST DATA

NON AIR POLLUTION CONTROL EQUIPMENT INVESTMENT COST	6668000.
AIR POLLUTION CONTROL EQUIPMENT INVESTMENT COST	8852000.
TOTAL INVESTMENT COST	15520000.
TOTAL INVESTMENT COST PER KILOWATT	98.23

AMORTIZATION PERIOD DATA

TIME TO COMPLETE CONVERSION IN YEARS	5
AVERAGE REMAINING USEFUL LIFE IN YEARS	20
INVESTMENT AMORTIZATION PERIOD IN YEARS	15

ANNUAL COST DATA

NON AIR POLLUTION CONTROL EQUIPMENT ANNUAL OPERATION AND MAINTENANCE COST DIFFERENTIAL	256000.
AIR POLLUTION CONTROL EQUIPMENT ANNUAL OPERATION AND MAINTENANCE COST DIFFERENTIAL	576000.
AMORTIZED TOTAL INVESTMENT COST	0.
ANNUAL FIXED CHARGE COST	4247374.
ANNUAL FUEL COST DIFFERENTIAL	-2416297.
TOTAL ANNUAL COST DIFFERENTIAL	2643077.
TOTAL OPERATION AND MAINTENANCE COST DIFFERENTIAL PER KWHR	.0011

Table 3. Illustrative Fuel Consumption Data and Values of Coal Conversion Measures

FUEL CONSUMPTION DATA

AVERAGE ANNUAL OIL CONSUMPTION IN BARRELS BEFORE CONVERSION	1254065.
AVERAGE ANNUAL NATURAL GAS CONSUMPTION IN MCF BEFORE CONVERSION	629457.
AVERAGE ANNUAL COAL CONSUMPTION IN TONS BEFORE CONVERSION	0.
AVERAGE ANNUAL BTUS BEFORE CONVERSION (IN MILLION-MILLIONS)	8,4498
AVERAGE ANNUAL BTUS AFTER CONVERSION (IN MILLION-MILLIONS)	8,4498
AVERAGE ANNUAL COAL CONSUMPTION IN TONS AFTER CONVERSION	352075.
EQUIVALENT ANNUAL BARRELS OF OIL SAVED AS A RESULT OF CONVERSION	1355005.

COAL CONVERSION MEASURES

ANNUAL COST PER EQUIVALENT BARREL OF OIL SAVED	1.95
CHANGE IN COST PER KILOWATT-HOUR OF ELECTRICITY GENERATED	.003472
INTERNAL RATE OF RETURN ON COAL CONVERSION INVESTMENT (PERCENT)	6.061
AFTER TAXES RATE OF RETURN ON COAL CONVERSION INVESTMENT (PERCENT)	3.209

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DIRECT FIRING OF COAL FOR POWER PRODUCTION

L. T. Papay

Southern California Edison Company
Rosemead, California

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ABSTRACT

The direct combustion of coal to produce electricity in California may require that the emissions from such a plant be less than those experienced with the combustion of low sulfur oil. Such a situation requires the use of new technology and advanced emission control hardware which has never been integrated into a single facility.

In order for various state agencies to accept coal within the state, it may be necessary to demonstrate that this integration will yield the desired results. A conceptual study conducted by Southern California Edison has revealed that it is technically feasible to conduct such a demonstration project on an existing, small 81-MW boiler.

Southern California Edison's studies on the question of trying to utilize coal to a larger extent in our generating mix (both from a capacity and from a fuel point of view) predate the oil embargo of late 1973. In these studies a spectrum of technologies was reviewed, and we came to the conclusion that liquids from coal were the preferred route because they were storable and could be decoupled from the generating unit. The Clean Fuels West project was initiated. In addition to ourselves, EPRI, Conoco, and Mobil participated. The preliminary engineering studies revealed one crucial problem. In looking at the forecasted environmental regulations for the State of California, it became apparent that there was probably no liquid fuel which would meet the projected stringent regulations with the exception of methanol. Methanol, of course, suffered from high projected costs, especially if produced from coal. Nevertheless, Southern California Edison has done a series of combustion tests, principally on oil from shale in conjunction with the Paraho project and others on a small utility boiler. In fact, we developed a new combustion technique for fuel combustion to try to minimize NO_x production. Currently, we, along with EPRI, have planned a methanol combustion test which will be started this summer.

Due to growing restrictions on energy and environmental options, a series of studies were done in-house over the last several years involving a variety of technologies (>40) and a number of departments. The principle results of these studies are given in Figure 1. It is clear that nuclear power is still the preferred economical alternative. Of the remaining technologies, direct combustion of coal, coal gasification integrated with a combined cycle plant, and geothermal were the three most promising alternatives. Coal gasification is the subject of another session, and a commercialization project involving Texaco and Southern California Edison will be discussed then. This paper focuses on the direct combustion of coal. Edison's program in direct combustion has two principle elements: demonstration on an 81 MW boiler at our Cool Water Generating Station, and the planned 1500 MW coal-fired plant in the Eastern California desert.

The direct combustion of coal to raise steam is a well-proven technology. The problem of meeting the extremely stringent air quality regulations in California and the public's perception of coal-fired power plants present the major challenges. Our experience in this area is contrary to the general perception of the impact of coal fired power plants on the environment. As the operator of the Mohave coal-fired power plant in southern Nevada, the data, based on our ambient measurements which have been in progress since 1968, or two years before the plant went operational, reveals that the operation of this plant is barely detectable in terms of annual ambient SO₂ levels using 0.4% sulfur coal. Coal of 0.4% sulfur content adequately meets current New Source Performance Standards (NSPS). The monitoring network extends up to 22 miles from the plant in the direction of the prevailing winds. The plant is equipped with electrostatic precipitators designed for particulate removal, which are adequate to meet current NSPS. Thus the plant meets current NSPS even though it was built prior to the adoption of these standards.

Figure 2 shows the southern California area and is useful in locating the projects mentioned above. First, Mohave is located in the southern tip of Nevada, just north

of Needles, California. For the proposed 1500 MW plant, three sites are being considered in the eastern California desert: Rice, southwest of Needles; Vidal, south of Rice; and Cadiz, northwest of Rice. The site for the 81 MW demonstration project is about 10 miles east of Barstow at Southern California Edison's Cool Water Generating Station. The solid lines in Figure 2 are the major railroads in southern California. As can be seen, Rice and Cadiz are quite close to railheads, while two railroads (the Union Pacific from Las Vegas, and the Santa Fe from Arizona) actually border the Cool Water site. This is an important factor in considering this site for the coal demonstration project.

Supplying coal to a site in California, whether by rail or perhaps by slurry pipeline, does not present a great problem. The principle question is the matter of the emissions from a coal-fired plant, since we recognize that regulations have become more stringent and that the public remains apprehensive. The objective of the Cool Water demonstration study was to see if we could design a plant which could burn coal cleaner than oil. Stearns-Roger conducted the study for SCE with this objective in mind. The particular unit which was used for the study is the Cool Water Unit No. 2. Cool Water No. 2 is an 81 MW Combustion Engineering boiler, which went into operation in 1964. One reason it was used in this study is that it was designed for possible conversion to coal. Out of our 9,237 MW of oil and gas-fired units, only a relatively few have that possibility. For example, the forced draft fan is oversized for oil-burning but is the proper size for coal. The air heater is also sized for coal burning. The cooling tower and condenser systems are oversized for oil firing but are sufficient for coal.

The turbine generator combination is sized such that with a small change to the turbine blading the unit will be able to generate enough extra power to satisfy the additional auxiliary power requirements for burning coal, with no reduction in the present electrical output of the unit.

Perhaps the most important aspect is that the boiler design is such that no change will have to be made in the superheater, reheater, or convection pass portions of the boiler because the tube spacing is adequate for coal burning. Also, the boiler foundation and structural steel design is sufficient to support the necessary additional equipment required for coal burning, and provisions were made to accommodate furnace expansion and the installation of the bottom ash handling equipment under the boiler without disturbing the structural foundation.

The original design of Cool Water Unit 2 included consideration of coal burning space requirements. For example, the space required for additional controls

and switchgear was provided in the control room and in the electrical room below the main control room. The switchyard was designed so that additional equipment could be added to provide the needed auxiliary power without moving any existing equipment. Also, a concrete room was installed beneath the boiler large enough to accommodate the required extension to the bottom of the boiler, the bottom ash hopper, and the bottom ash handling equipment. Finally the site is large enough to allow space for a long-term ash storage area without interfering with the equipment or facilities.

Figure 3 is an artists rendering of the coal demonstration plant at Cool Water. In the figure, some of the special precautions that will be taken to contain all fugitive dust from coal and ash handling operations are visible. Spray treatment of the rail cars (at the mine) will prevent windborne dust during transportation of the coal to the plant site. During rail car unloading, a dust suppression system will be employed inside a totally enclosed building. The coal will be dumped from the bottom of 95-ton coal cars and any coal dust present in the building will be collected in a filter system. Coal storage at the site will consist of three 2000-ton enclosed silos, each having a dust collection system. There will be no open coal storage during the demonstration test program.

Primary coal crushing will take place in an enclosed building utilizing another dust collection system. Also, all the coal conveyor belts will be enclosed.

The boiler will be converted from a pressurized system to a balanced draft system. Therefore, the boiler will be at a pressure slightly less than atmospheric so that any possible leakage will be into the boiler rather than out of it.

Fly ash handling will utilize a vacuum conveyor to draw the fly ash through pipes into a completely enclosed storage silo. The fly ash will be trucked away in trucks fitted with special dust control features.

Finally, the structures immediately to the left of the boiler in Figure 3 will contain the pollution control system.

The criteria for direct coal-fired technology are shown in Figure 4. In addition to demonstrating emissions less than that which you would have with burning low sulfur oil, it is desirable to have a coal to electricity heat rate of around 10,000 BTU/kWh with capabilities to get even lower heat rates (or improved efficiency). Figure 4 shows that we are considering time dependent targets in these areas. The 1978 data is related to the present state of the art. It is clear that we must be able to translate the information from this demonstration program to the 1500 MW coal-fired

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plant of the late 1980's.

The problem then is to provide an adequate demonstration of control of particulates, SO₂, and NO_x, while retaining a respectable heat rate. The problem is compounded by the fact that advanced technologies for emissions control have not been operated in series on the same utility boiler.

Particulate, SO₂, and NO_x control technologies are the subject of another session at this conference, so this paper does not dwell on them at any length. However, it is important to place these technologies in perspective relative to Edison's coal development program.

New technology has emerged since the early 1970's for achieving very high levels of pollution control with conventional coal-fired plants. For example, fabric filtration, which involves the use of bag filterhouses, was first successfully demonstrated at a coal-fired plant in 1973. Today, several thousand megawatts of electric generating capacity are being fitted with baghouses for new and existing coal-fired powerplants. Stack sampling conducted by the Electric Power Research Institute, and others, has shown that in excess of 99.5% of the particulate matter resulting from coal combustion can be removed with a baghouse if it is working properly. This requires an air-to-cloth ratio of about 2.0 ACFM per square foot, or less, for conventional reverse air type baghouses. Advancements have been made in the bag materials such that operating temperatures up to 450°F with bag lifetimes of two years have been achieved.

The primary advantage of a baghouse is that there is no visible smoke plume under normal conditions. If there is a visible plume, then one or more of the bags has been damaged or broken. The problem area can then be quickly identified and corrected without shutting down the generating station. This is accomplished by sequentially isolating individual bag compartments until the plume disappears, and then entering the compartment where the problem exists to replace the damaged bags. When the powerplant can operate without a visible smoke plume, there is much more of a tendency for the general public to believe that the insignificant levels of pollution actually are insignificant.

One of the problems with smoke plumes is that the density, or opacity, is more a function of the sun angle and viewing position than any other factor. A smoke plume will always appear more dense when viewed with the observer facing towards the sun than with the sun at the observer's back. One example of this is a car which is being driven in a direction towards the sun, and also happens to be very smoky or on fire. It is very hard

for the driver to see any smoke, but all the other drivers behind him cannot avoid seeing billowing clouds of smoke. This is a case which is similar to viewing a smoke plume from a powerplant -- what you may see is not a very strong function of what is actually there. Since it is very difficult to convince people that their eyes can deceive them, it is becoming increasingly attractive to install bag filterhouses on coal-fired powerplants and completely eliminate the problem of a visual smoke plume.

Most of the experience with electrostatic precipitators is with "cold-side" precipitators, that is, precipitators downstream of the air preheater. There is limited experience with hot-side (upstream of the air preheater) precipitators. Although we have chosen a baghouse for the demonstration program it should be pointed out that the final NO_x control configuration may require a reevaluation of our particulate control equipment.

Wet alkaline scrubbers for SO₂ removal have also been developed since the early 1970's. Early experience identified severe problems in the formation of chemical scale inside scrubbers which caused severe operating and maintenance problems. The chemistry of lime and limestone scrubbers is very complex, and basic research is still being conducted on methods of preventing scale formation. However, sufficient engineering know-how has been developed to solve most of the problems encountered with wet scrubbers. Several thousand megawatts of coal-fired generating capacity are currently operating with scrubbers, and a wide variety of commercial systems are available. The choice of a horizontal cross-flow lime scrubber is based on Edison's extensive work done at Mohave including the operation of two large demonstration units.

Some work has been done on various methods for the disposal of flyash and scrubber sludge which is discharged as a consequence of coal-fired powerplant operation. Many types of flyash can be wetted and compacted to form a very hard, impervious landfill. Flyash is sometimes sold as a commercial byproduct used in cement manufacturing or as a road base. Sometimes, the flyash is mixed with the scrubber sludge to promote stabilization of the mixture, with or without other chemical additives. Scrubber sludge resembles plaster of paris, but will not harden by itself. Successful experiments have been conducted to manufacture wallboard from scrubber sludge. It has also been used successfully as a substitute for natural gypsum in the manufacture of Portland cement. Both flyash and scrubber sludge can be used as soil amendment additives and/or crop yield improvement additives, depending on the type of soil, the dosage rate, and the type of crop. Further research to identify suitable end-uses for

these products of coal combustion are still in progress.

The most difficult pollution control problem with coal is NO_x . Coal-fired boilers are being offered today which can achieve an NO_x emission level of about 225 ppm (corrected to 3% excess oxygen). This is cleaner than most oil-fired boilers, but has never been demonstrated during long periods of continuous operation on a full-scale powerplant. The Electric Power Research Institute is also developing low NO_x coal burners which may be able to do even better, perhaps down to 150 ppm.

Other technologies exist on a laboratory or pilot plant scale which use ammonia or other chemicals to reduce NO_x emissions. Since ammonia is presently made from natural gas, and is a main ingredient for fertilizer, it is not apparent that it would benefit the nation to divert thousands of tons per day of this resource for the purpose of NO_x control in coal-fired powerplants. The benefits become even less apparent when an emissions inventory for urban areas indicates that automotive NO_x emissions are a much larger percentage of the total -- for example, about eight times more than the total power plant NO_x emissions in the Los Angeles area. Also, it is not clear to what extent any of the emissions, particularly NO_x , will affect ambient air quality.

Thus, although we do not agree necessarily with the regulatory agencies as to the level of control which may be required at Cool Water or for the 1500 MW plant, we are looking at the various alternatives. Figure 5 illustrates the problem with which we are confronted. The data in this figure was supplied by EPRI. First, there are several technologies which have to be evaluated: low NO_x burners, ammonia injection, and ammonia with catalysts. None of these technologies is commercial today, each offers differing possible levels of control, and each is being developed under a different schedule. The problem is compounded by the fact that the particulate control system may be affected by the choice of NO_x control system.

With all of these concerns, the need for adequate pilot and demonstration projects becomes quite apparent. By integrating the EPRI pilot work in NO_x and utility experience in baghouses and scrubbers, a first of a kind demonstration of advanced particulate, NO_x , and SO_2 control systems can be envisioned. A schematic of the possible arrangements is shown in Figure 6. Of course, an ambient air monitoring program will be conducted at Cool Water to measure the plant's impact, if any, on ambient air quality. This then, is the primary purpose of the Cool Water direct coal-fired demonstration project: to take several diverse independently developed technologies and operate them in an integrated

fashion with a conventional boiler; to try to do this in a reliable and economic manner, while still demonstrating that it is environmentally acceptable.

**LIFECYCLE POWER COST ESTIMATES
(1975 FUEL PRICES)**

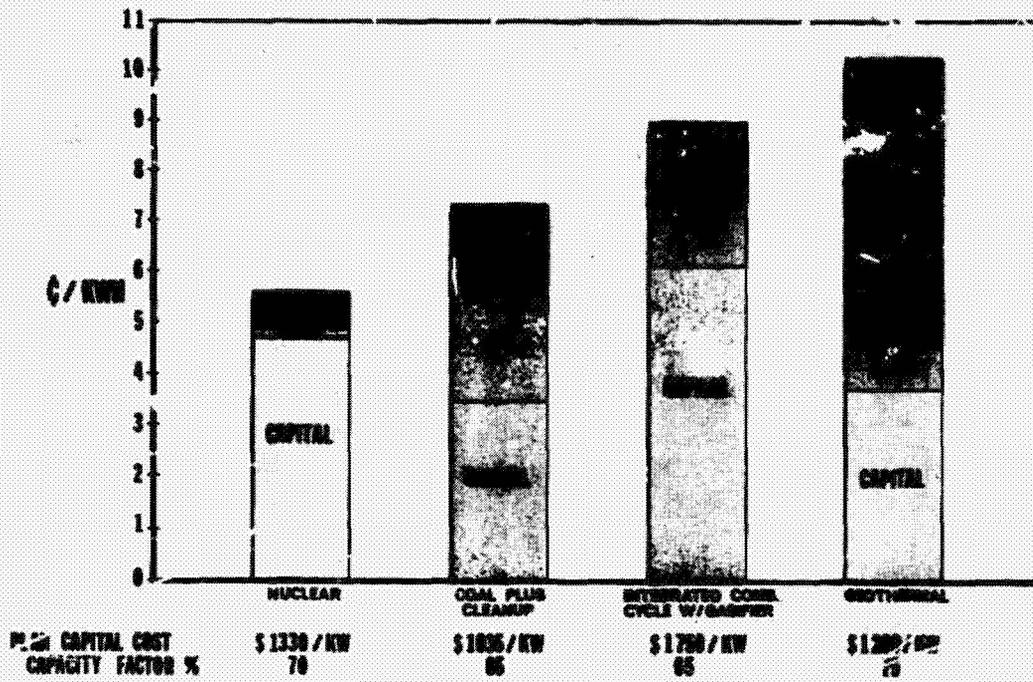


Figure 1 - Economics of Alternate Technologies

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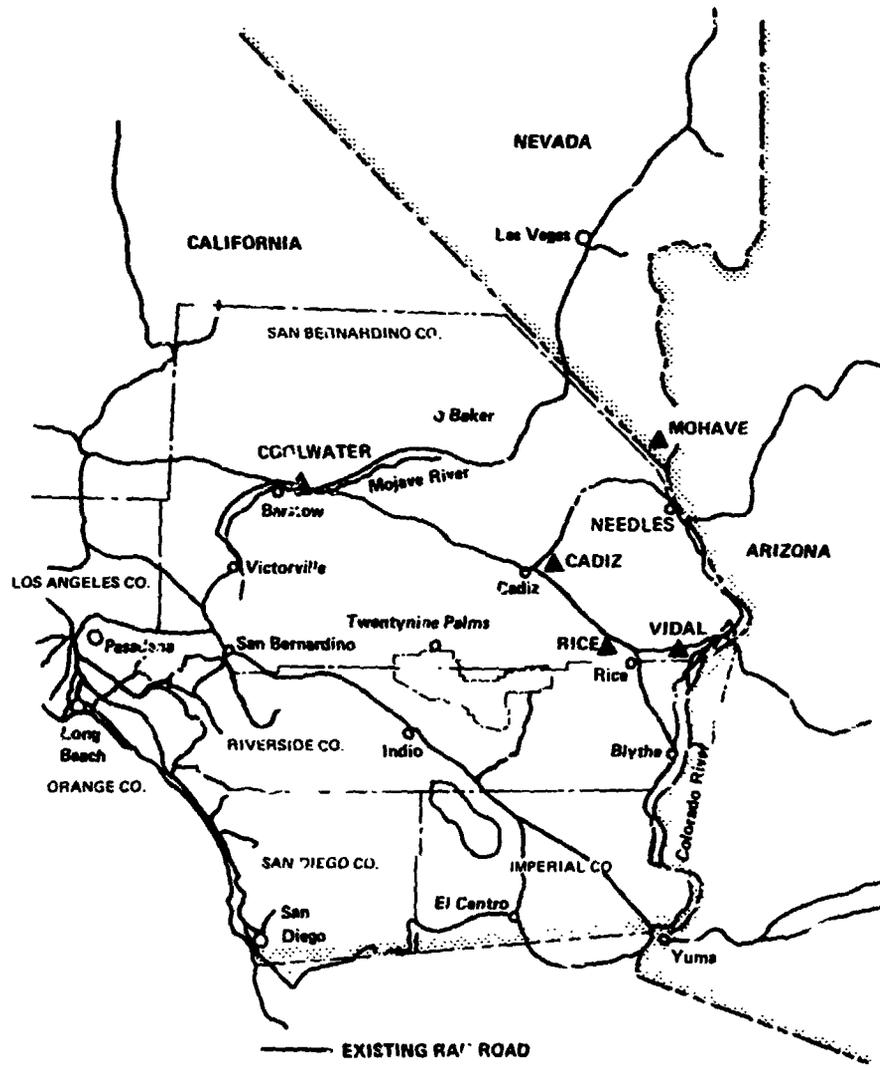


Figure 2 - Southern California Area

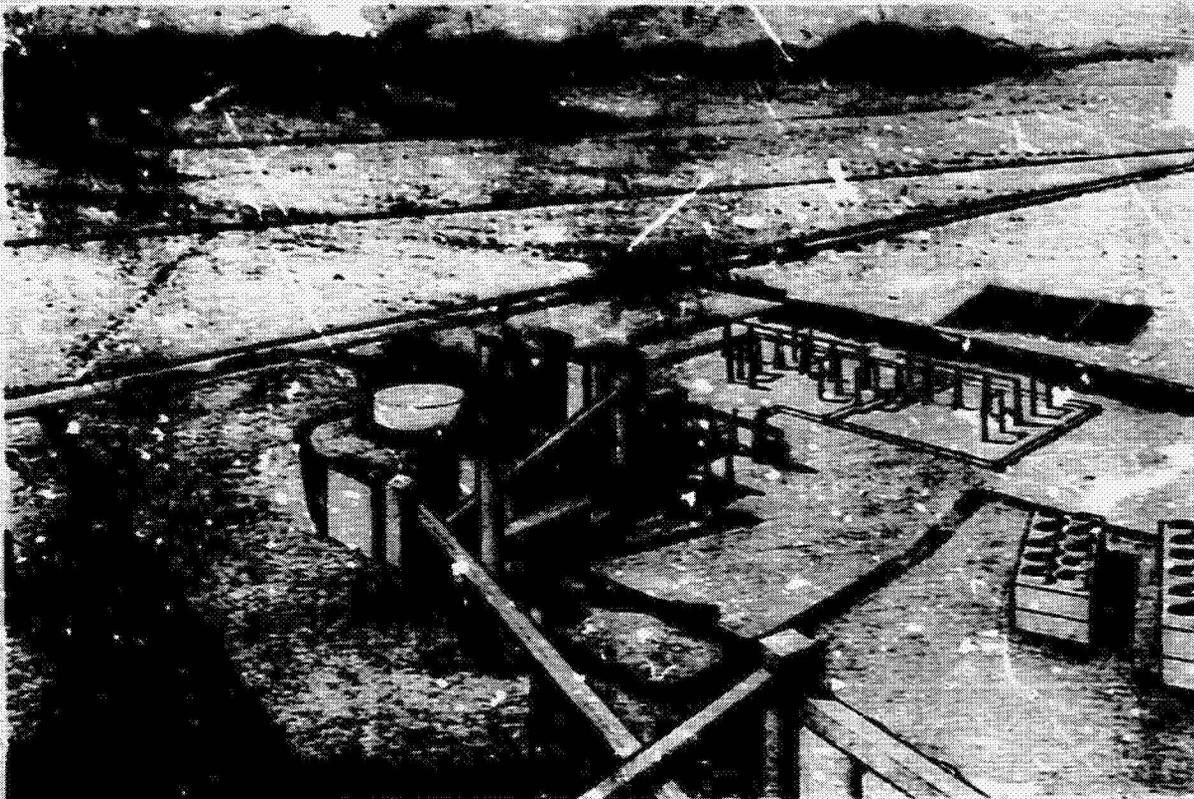


Figure 3 - Coal Demonstration Plant

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DIRECT COAL COMBUSTION

	<u>HARDWARE ORDER DATE</u>	<u>PREDICTED RESULTS (ESTIMATES)</u>
Emissions	1978	Particulate (99.80% to 99.98% removal)
	1978	SO ₂ (80% to 90% removal)
	1978	NO _x - Advanced combustion (20% to 40% removal)
	1983	NO _x - Advanced combustion plus Catalytic NH ₃ injection (80% to ? removal)
	1978	Opacity (smoke plume density) < 1%
Efficiency	1978	Small demonstration plant (80 MW) - 10,600 BTU/KWH
	?	Large new plant (800 MW) 9,300 BTU/KWH
Commercialization	1981-82	Initial demonstration tests completed
	1986-88	Startup of first commercial plant

Figure 4 - Coal Combustion Criteria

NO_x CONTROL TECHNOLOGY DEVELOPMENT SCHEDULE FOR COAL-FIRED BOILERS

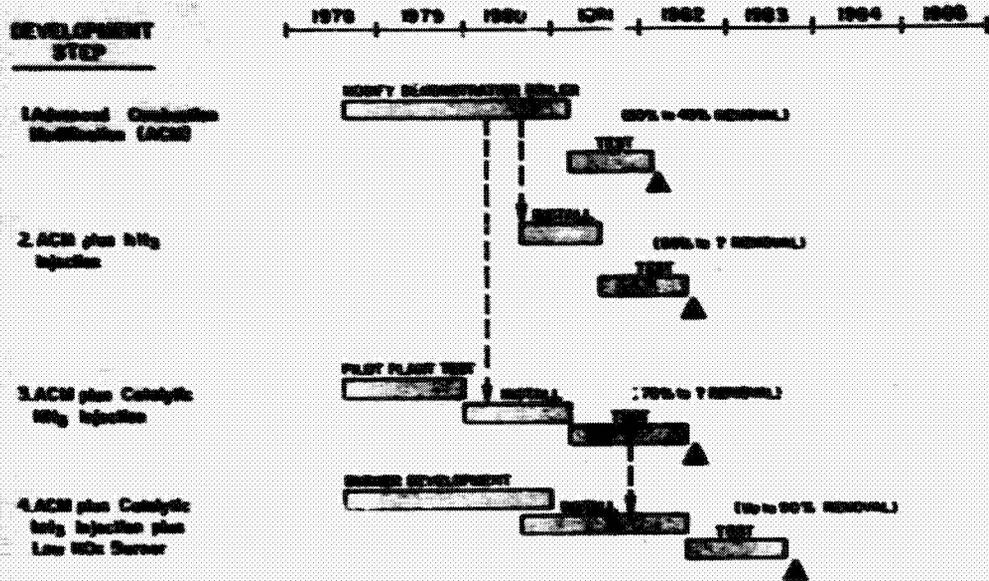


Figure 5 - Coal Boiler Advanced NO_x Control (PR1)

DIRECT COAL COMBUSTION

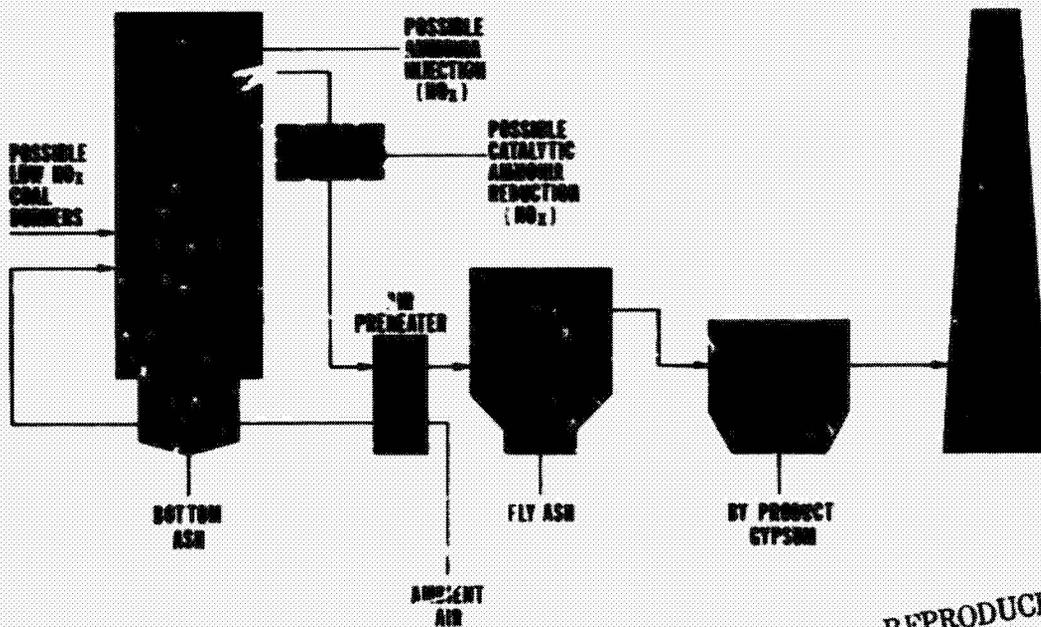


Figure 6 - Coal Combustion with Integrated Controls

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FLUIDIZED COMBUSTION OF COAL

Michael Pope
Chief Executive Officer

Pope, Evans and Robbins Incorporated
New York, New York

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ABSTRACT

A new combustion technology has been developed in the last decade that permits the burning of low quality coal, and other fuels, while maintaining stack emissions within State and Federal EPA limits.

Low quality fuels can be burned directly in fluidized-beds while taking advantage of low furnace temperatures and chemical activity within the bed to limit SO₂ and NO_x emissions. The excellent heat transfer characteristics of the fluidized beds also result in a reduction of total heat transfer surface requirements. Tests on beds operating at pressures of one to ten atmospheres, at temperatures as high as 1600°F, and with gas velocities in the vicinity of four to twelve feet per second, have proven the concept. The progress that has been made in the development of fluidized-bed combustion technology and work currently underway are discussed.

I. COMBUSTION IN A FLUIDIZED BED

Our organization has been involved in combustion technology since 1906, and, through the decades, has designed many first-of-its-kind facilities for industry, to burn waste or by-product fuels, in addition to fossil fuels.

One of the more promising technologies which will enable the use of low grade fuels in an environmentally acceptable manner is atmospheric pressure fluidized-bed combustion.

Direct-contact heat transfer Fluidized-Bed Combustion (FBC) involves the burning of fuels in a bed of inert granular material (ash, limestone or dolomite), which has been held in suspension by the injection of air through a distribution grid at the bottom of the bed. Combustion within the fluidized-bed is very intense with high volumetric heat release, and very high heat transfer rates are obtained with immersed heat exchange surface. As a result, furnace size as well as the amount of heat transfer surface and hence, cost, is reduced.

Fluidized-beds have been used for decades in the chemical industry to enhance reaction rates, but their use in steam generators is a new concept. In early 1965, I started a hardware development program to prove that fluidization could be applied to coal burning. With funding from DOE's predecessor agency, the Office of Coal Research, we designed and built in Alexandria, Virginia, the world's first fluidized bed boiler in late 1965.

Tests at our laboratory, as well as those performed in later years by others, on beds several feet in size and several feet deep, operating at temperatures around 1600°F, and with gas velocities

in the four to twelve feet per second range have proven the concept. Tests have also demonstrated a capability of burning low-grade fuels, and transferring heat at average rates several times those expected in conventional boilers.

II. FUELS USED

Fuel types are unlimited. Unlike a conventional coal-fired boiler, ash properties are not a significant factor here. Also, the bed temperature is too low for the ash to soften. It is a universal machine in that the same basic design applies for all fuels. All fuels are burned at a heat release rate equivalent to 100,000 Btu/ft²/hr per square foot of effective projected radiant surface (EPRS).

III. OPERATION

Start-up of the combustor requires heating a portion of the bed to a temperature hot enough to ignite the fuel used. After ignition, the temperature of the bed rises rapidly until the system achieves thermal equilibrium.

Operating characteristics of the bed dictate an optimum design temperature range of 1500 - 1600°F, with excess oxygen at about 3 percent. At these conditions, about 50 percent of the heat released by the burning fuel is absorbed in the immersed tubes.

Solid and liquid fuels burn rapidly. The rate is so high that at any point in time a sample of bed material would analyze at about 2 percent carbon.

Fireside corrosion is avoided, because the sodium, potassium and vanadium in the fuels, if released, are picked up by the bed particles.

IV. RIVESVILLE

The Department of Energy (DOE) financed 30 MW_e demonstration unit at Rivesville, West Virginia ranks as the largest of the world's growing family of operational test installations. Situated at a Monongahela Power Company generating station, the systems were designed, and their construction supervised by Pope, Evans and Robbins (PER). The boiler proper was built by Foster Wheeler.

The Rivesville unit features an array of four cells, with overall dimensions of 12 ft wide by 39 ft long by 20 ft high. It burns 14 tons/hr of coal to raise 300,000 lbs of steam per hour at 1300 psig and 925°F for power generation by the Power Company.

The steam output capacity of the Rivesville unit would more than satisfy most industrial users.

The central station installations will have to wait for a larger demonstration unit, now planned for the early 1990's.

V. POLLUTION CONTROL

Tests performed by federal agencies on our pilot unit established that both NO_x and SO_2 emissions were held below federal EPA emission standards for new plants. Test data showed emissions well under 1.70 lb $\text{SO}_2/10^6$ Btu while burning coal with 4.8 percent sulfur; and NO_x readings of 0.11 to 0.17 lbs per 10^6 Btu.

The solid fuel fed to the combustor is normally crushed, not pulverized, to a 1/4 - 3/4 inch size. A good fraction of the ash remains in the fluidized-bed where it is drawn off, or if carried out with the products of combustion, is separable in a cyclone collector. However, in order to comply with current pollution control regulations, the use of bag-house filters, or electrostatic precipitators are required.

Sulfur dioxide in the fluidized-bed is controlled by the use of limestone as bed material. The bed is kept reactive either by the addition of fresh limestone, in a once-through system, or by regeneration to recover sulfur dioxide in useful concentrations.

Four studies are now being undertaken by EPA to develop alternate plans for calcium sulfate (CaSO_4) disposal. We have used it as a soil conditioner to grow successful crops of peanuts and corn.

To encourage wide-spread use of FBC, DOE is co-funding demonstration units for process steam and for direct and indirect heating of other fluids. One of these, which we are designing, is a 100,000 pph unit at Georgetown University in Washington, D.C., to prove that coal can be burned, in an urban area, without polluting. This is a two cell, rather simple unit designed for industrial/institutional use. We are using a spreader to feed the coal. Note that we are burning a coal with 3% sulfur. For California area coals and to meet Bay area emission standards of 0.6 lb/ MMBtu , about a 70% sulfur reduction is necessary - limestone requirements would be in the range of 1% of limestone for 8% of coal. Current major AFBC projects are being funded by DOE and the State of Ohio. DOE is not carrying the entire burden of FBC facilities' sponsorship in the United States. EPA is funding a test unit at Exxon Research in Linden, New Jersey. Exxon's mini-plant has a broad range of operating capabilities; pressures up to 10 atm, and bed depths of 20 ft. It completed shakedown in 1976, and has accumulated 1,100 hours of operating time, including a 10 day sustained run.

The Electric Power Research Institute (EPRI) in Palo Alto is sponsoring an FBC test unit too, with Babcock & Wilcox at its Alliance, Ohio research center. That facility, capable of burning 3,000 lbs of coal per hour was recently put into its initial phase of test operation.

Together with B & W (U.K.), Combustion Systems Ltd. of Great Britain designed and constructed at Renfrew, Scotland, what's claimed to be the

largest FBC unit running in Europe today. Started up in June, 1975, the 10 sq ft atmospheric pressure combustor (a converted stoker-type, water tube boiler) produces 21,000 lb/hr of steam.

American Electric Power Co. is pursuing the pressurized FBC system which utilizes gas turbines as the main electric power producer. A small pilot plant at Leatherhead, England, which has been operating since the late 1960's, has developed most of the technology on which the company bases its system.

Meanwhile, the National Coal Board is shepherding a \$25 million project of the International Energy Authority. This calls for construction in England, of a pressurized FBC pilot plant by 1980. The unit is expected to operate at 20 atm and yield about 20 MW_e . Elsewhere in Europe, West Germany's state-owned coal mining and energy company announced a cooperative agreement with the Coal Board.

Also, back in the United States, by 1980/1981, an elevated-pressure unit should also be turning out 13 MW_e from an expansion turbine, fed both by combustion off-gas and air, heated in the coils. DOE awarded a \$25 million contract for the 13 MW_e plant to Curtiss-Wright Corp.

DOE is also planning a pair of facilities to check on the compatibility and possible modifications of various FBC system components. An atmospheric pressure system rated at about one-third of the capacity of the Rivesville installation, will be built at DOE's Energy Research Center at Morgantown, West Virginia, and a similar size high pressure boiler will be constructed at its Argonne, Illinois laboratory. DOE expects both of the units to be onstream in the early 1980's.

VI. EXPECTED BENEFITS

Fluidized-bed combustion is expected to make it possible to build industrial, process and utility combustors within the next several years that will produce the following benefits:

1. Low grade fuels, including petroleum coke, municipal waste, biomass and wood chips can be efficiently and economically burned, meeting clean air criteria, without the use of stack gas clean-up systems.

2. Sulfur dioxide emissions are reduced by the limestone bed, and NO_x emissions are reduced by the low combustion temperatures.

3. Smaller in size and lower in cost than presently available combustor types, capable of burning high-sulfur fuels within clean air standards. The technical factors that make this possible are the higher heat release rates and higher heat transfer rates.

4. Plant space and construction time savings, due to shop fabrication of the component cell sections with expected increase in equipment quality.

5. Solid fuels of higher ash content may be economically burned, since crushing is limited.

6. Requirements for pulverizers are eliminated since it is not necessary to reduce the size of the coal below $\frac{1}{4}$ inch.

7. Slagging problems are eliminated since the combustion temperature is maintained below the ash fusion temperature.

8. Independently controlled multiple modules should result in high operational availability and the ability to "stay on-line" if a mechanical failure occurs in a module.

9. Modular design minimizes capacity scale-up problems.

New Federal EPA regulations are now being debated. We anticipate a reduction in new source performance standards to .03# of particulate per 10^6 Btu, and to 0.6# of NO_x for 10^6 Btu. For sulphur, the battle rages between 80-90% sulphur removal. A compromise will be reached.

The Energy bill, still stalled in Congress, has provisions for mandatory coal conversion that have been agreed to by both the House and the Senate. All new boiler plants with capacity over 100,000,000 Btu must burn coal as the primary fuel.

The options now available to industrial steam users are few. So called compliance coal, low in sulphur, will lose its designation with the new EPA regulations requiring sulphur reduction.

In summation, it is apparent that California must learn to live with coal for the next 50 - 75 years, if it wishes to maintain its standing in the economic community.

Since Amory Lovins has blessed FBC by including it in the category of "soft technologies", I recommend it to California.

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**THE NATIONAL COAL POLICY PROJECT: HOW ITS
RECOMMENDATIONS APPLY TO CALIFORNIA**

Larry Moss and Gerald Decker

Dow Chemical Company

The National Coal Policy Project (NCPP) was organized to determine if key people from the environmental movement and industrial organizations could agree on desirable public policy in the production and use of coal. The motivation for seeking such agreement was the feeling that, on issues where it could be achieved,

more rapid progress in implementing policies acceptable to both sides would then follow. The processes used and the more important of the agreed-upon recommendations will be described. The application of certain of these recommendations to the California situation will be discussed.

NOTE: The complete paper was not available at the time of publication.

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SESSION VII: COAL TECHNOLOGY - DIRECT FIRING

Session Cochairmen: John Belding (DOE)
George Cavalas (Caltech)

Speakers: John Rau (Ultrasystems, Inc.)
Larry Papay (SCE)
Mike Pope (Pope, Evans and Robbins)

OPEN DISCUSSION BY ATTENDEES

TED RAUGH

I am with the California Energy Commission. Dr. Papay, in your discussion of the demonstration plant for the direct firing of coal, you stated that this will cover a 4 to 6 year period. If I understand it correctly, Edison's view apparently is that it is necessary to complete a successful demonstration at this 80 megawatt level before the utility would be convinced that it could scale up to larger size units, such as perhaps the 1500 megawatt plant, that you mentioned earlier. Is this generally correct, I mean is Edison saying that we need to have a demonstration at this lower level before we know that we can go to a much larger plant in Southern California and at the same time show that the various control devices for the various pollutants are going to satisfactorily meet the standards etc?

LARRY PAPAY

A final decision on this has not been made, but the philosophy that we're using here recognizes that the requirements for a 1500 megawatt plant requires that we minimize the risk in the entire process of the designing construction and operation of such a 1500 megawatt facility. This risk is minimized if you can demonstrate the state-of-the-art at a reasonable scale; that is, at the 80 megawatt level. We would put together components that

have not been placed in a series before. Individually, except in the case of the NO_x technology, they have been operated at the 80 megawatt size or larger. There is a great deal of information that you can feed into the design of the components of a 1500 megawatt sized plant. I think everyone within Edison has come to this conclusion.

TED RAUGH

When would the 1500 megawatt come on line according to present plans?

LARRY PAPAY

That is the late 80's. I don't know if there is a set date but it is in the 1987-1988 time frame. We're looking for initial startings in 1981 for the MW demonstration project. Since this represents a conversion, and if we reduce emissions from what they are currently, and there is no additional capacity, we do not need as many regulatory permits.

You can change your design, and you can vary your strategy as time goes on as a function of what happens in a demonstration program such as this. If we started up this demonstration on unit in '81, or whenever we would start it up, the first few months of operation might be horrendous from the point of view of total number of operating hours, simply due to the newness of the systems involved. However, as you get closer to making commitments for procurement of components and finalizing designs on the 1500 megawatt plant, the amount of information that you'd have and could utilize would be growing simultaneously.

DALE JONES

I'm with Southern California Edison Company. I had a brief question for Mike Pope on the fluidized bed combustion because one of the slides seem to indicate compliance with SO₂ regulations without scrubbers, and being from the West with low sulphur western coal I wonder if you had any data on making say up to 90% SO₂ removal of the fluidized bed concept.

MIKE POPE

We could actually make 90% or any sort of removal that you want by just adding more limestone.

DALE JONES

What happens to the quantities of waste?

MIKE POPE

You tell us what SO₂ emission you want off the stack. The emission control the limestone feed to the boiler.

DALE JONES

What sort of stoichiometric limestone usage would you expect?

MIKE POPE

Calcium sulfur ratio of about 3:1. What I'm really saying is that you tell us what you want off the stack and that determines the amount of limestone.

DALE JONES

So you are talking about 35% of the agent utilization.

DONNA PIVIROTTA

I am from JPL. I wanted to ask Mr. Pope if he has done any cost projections on the fluidized bed in a power plant situation.

MIKE POPE

Yes we have, I should point out that we are working with Foster-Wheeler and their boiler expertise. The overall capital cost is about 10 or 15% less than a pulverized coal unit with a stack scrubber. We would expect a comparable reduction in operating costs as well. Perhaps around 10 percent.

JOHN BELDING

Not to mention the ease of getting rid of the by product or waste.

MIKE POPE

Yes, we have not cranked into those costs, the operation of sludge disposal.

JOHN BELDING

Fluidized beds do have a solid waste that's nice and handable.

MIKE POPE

That's calcium sulphate and I have a sample of it in my briefcase if you would like to take a look at it, it's dry. It doesn't even kill rattlesnakes.

CHARLES MANN

I'm with the Energy Environmental Analysis. A couple of things addressed to Mr. Pope. In the last month, I have talked with about 10 large industrial companies about their plans to use coal. Most of them being engineers, are fascinated with fluidized bed and would like to go that way. None of them feel that it's a proven technology and I wonder what you think is the threshold or the critical state, for which somebody at a large corporation would be willing to sign on the dotted line?

MIKE POPE

That is such a difficult question. I told John Belding before this session started that we've completed no fewer than 12 feasibility studies for industry and they are all right at the threshold. They would like to use fluidized beds. However, if they were going to hardware today and some of them are going today, they are going with spreader stokers. They are going with a known quantity flue gas desulfurization, that's hard for them to swallow, but they are going that way. The reason for it is because the boiler companies are not stepping forward, that is other than Foster-Wheeler, which is going to offer a qualified warranty. But this pertains only to one unit. The technology has arrived but just hasn't crossed that door yet and if you were to ask me to make a recommendation today for an industrial client, I would say go spreader stoker.

CHARLES MANN

One other thing which is more informational. You mentioned the 250 million BTU cutoff, which has been taken for granted. It might continue to apply in EPA's revision of the new source performance standard for industrial steam units. There is no clear authority in the Clean Air Act amendments in 1977 to distinguish between industrial and utility boilers. The revision of the new source performance standard and the technology may exist, or at least some people would argue that it exists, for 90% removal down to essentially zero size coal fired boilers.

BERNIE GROTZ

I am with C.F. Braun & Co. Mr. Pope, can you tell us about the turn down capability and control of turndown capacity is for your boiler.

MIKE POPE

You get about 2 to 3 to 1 turndown per cell, and again with a 2 cell unit you could expect about a 4 to 6 to 1 turndown. On a 4 cell unit you just multiply.

BERNIE GROTZ

These are in parallel cells you mean?

MIKE POPE

Yes.

BERNIE GROTZ

What is the method of control for turndown?

MIKE POPE

Coal feed-on and controlling the depth of the bed. When you have immersed tubes the way you control it, dramatically is to drop that bed depth so that some of the tube surface is exposed rather than immersed.

DON PETERSON

I am with the California Energy Commission and the University of San Diego. The question is for Dr. Papay. I have been standing here trying to figure out how to ask it diplomatically. I'll refrain from being facetious, but yesterday we heard Mr. Austin from the Air Resources Board talk about control technologies, commercially available, which seemed to be superior to the ones which you are planning to experiment with. I don't know exactly how to ask the question, but I guess I would like reflections on what the difference is between ARB opinion and your company's opinion on what is possible and what isn't?

LARRY PAPAY

Unfortunately, I wasn't here yesterday, so I don't know what Mr. Austin did say but truthfully we don't necessarily always agree with the ARB on the status of technology.

DON PETERSON

I think in terms of NO_x if I'm correct, he was talking of something on the order of 10th of a pound per millior BTUs. I think he also said that this was commercially available. I think in SO_x he was talking about .05 pounds per million cubic feet and that is considerably better than what you are talking about. The only reason I'm asking this is because I'm sure other people are probably confused by this apparent difference in what is and isn't possible.

THOMAS AUSTIN

Larry, if you want me to clarify that, what I said was, .01 pounds per million BTU heat input for particulate, which is pretty close to some of the numbers we were talking about earlier today. .05 pounds per million BTUs for SO_2 , which is not as low as has been demonstrated on several Japanese power plants and .1 on NO_x which would require you to get down to around 200 ppm with your basic furnace and something like the Exxon ammonia injection on top of it.

LARRY PAPAY

I might even think that ammonia injection at the burners wouldn't get you to .1. I think you might have to go with something more.

The choice of the SO₂ scrubber, plus the bag house was essentially aiming at clean up numbers which are somewhat the same as those just presented. I'd say the difference of opinion would be the question of what level and when will the NO_x control systems deliver. This is exactly why the demonstration on the Coolwater unit No. 2 to us makes a great deal of sense rather than going straight to something on the order of 1500 megawatts. The experience in the US is quite limited. I realize there is some experience in Japan on ammonia injection and catalytic ammonia systems. In the US the EPRI coal pilot plant at Arapajo is at the 3 megawatt level. EPA's pilot plant is in that neighborhood. So we're looking at it from that point of view. What we are proposing represents a good step up as far as that technology is concerned.

On top of that, though is the fact that nobody has strung these systems together before. There is a bag house here and a bag house there and a scrubber here and a scrubber there, but what we're talking about is putting these several technologies in series. From a utility point of view what we are looking at makes a great deal of sense.

RICK FLAGAN

I am from Caltech. I have a question for Mr. Pope. First, the nitric oxide numbers that you mentioned, are considerably lower than the numbers that have been reported in numerous other studies. Is this a result of the bed material or do you have any comment on the NO_x?

MIKE POPE

We have gotten a wide range of readings depending on operating conditions. The official test, conducted by the Pittsburgh Test Center several years ago in our Alexandria Facility, recorded

readings in the .11 to .17 range.

RICK FLAGAN

There have been numerous other studies that have been 3 to 4 times that.

MIKE POPE

I know. I know.

RICK FLAGAN

Second question, would you comment on the character of the particulate matter that is produced by the fluidized bed, especially the submicron particles. What I'm interested in, is what is required in the way of control for the electrostatic precipitator or bag house.

MIKE POPE

I don't know quite how to answer that, you say comment on it. We are using state-of-the-art. We make no claims in regard to particulate emission control.

RICK FLAGAN

What is the nature of the particulate matter? As Dave Ensor commented, the efficiency of a precipitator or bag house depends upon the size distribution of particles, possibly also on the chemical and physical nature of those particles.

We are not really getting anything different in a fluidized bed unit than you would get on any PC unit.

JACK KEELTY

I am with Foster-Wheeler. I just want to clarify one of your remarks, Mike. Foster-Wheeler is now making commercial guarantees on fluidized bed boilers.

MIKE POPE

I know, I heard Bill Stevens say that, but I haven't seen that first order yet.

JACK KEELTY

I haven't either. I have been asking for it for 6 months, so we are still looking for those guarantees.

FRANK PRINCIOTTA

Just a brief point of clarification regarding the new source performance standards. The standards that we have been talking about, the revised standards that are imminent, only apply to the utility boilers. There is some misconception about that over a certain size range. There will be separate standards for industrial boilers, which will probably be proposed sometime late this year or early next. There seems to be a little bit of confusion on that point.

RON ENECHT

I'm with the State Energy Commission. I'd like to change subjects for a minute and go back to something that Dr. Papay mentioned in passing; that is the thing that you started with the economics of various technologies for power generation. I couldn't see from way back in the back, where I was sitting, the fine print on your slide there and I'm wondering if you have the assumptions that go with that. In particular I'm looking for the fuel costs that go with the nuclear, the O and M costs and a number of other things. I think probably the people from California here, people from the utilities, are aware that the Energy Commission has dissented directly with you on whether, in fact, nuclear is the economic choice over coal, in the way that your bar chart seemed to indicate. Can you give me the details on that or could you maybe provide that at a later time?

LARRY PAPAY

I think that perhaps the best thing would be for me to provide you a copy of the chart. In any case it will be in the proceedings.

BON KNECHT

Let me just make one or two comments on some of the economic data that has been shown. I personally have done fairly extensive studies on cost economics of nuclear and coal power plants. For example, there were some dollars per kilowatt capital costs shown in this session today for about 8 or 9 plants. I recognized 2 or 3 of those right off. The data were so far out of date, which doesn't mean they were very old, they might only be 2 or 3 years old, but the data were so far out of date there were 2 or 3 of those plants where the utility's current estimate is already about twice what which was shown on the chart.

The reasons that I'm bringing this up in particular, is that it could make a difference when you look at the economic viability of various coal cleanup options; you use recent data, you use recent cost estimates of \$30 or \$100 or whatever per kilowatt, you should know whether you are comparing those numbers to \$500 kilowatt or \$1000 per kilowatt because that will make a very big difference.

It's too bad that we can't somehow sit down and all get together on the assumptions that go into these. The assumptions dictate the results on this cost assessment stuff and the assumptions have been changing not just rapidly but volatily over the last 2 or 3 years.

In general I don't think that the nuclear option is significantly economic over the coal option and may not be at all. I would say also that I think all the cost figures that I have seen today are low compared to what you would get if you did a May 1978 assessment.

MIKE POPE

One or two other comments as far as stack gas emissions on our unit. That task has been taken over by EPA and they've subcontracted with Battelle, who will be fully set at Rivesville by July with their trailer and we hope that out of those tests will come the best available control technology. There was one other comment - question that I don't think I answered fully as to what it will take to bring this technology across the threshold. I think the answer there is really a greater involvement on the part of the boiler companies.

Except for Foster-Wheeler, B&W is rather new on the scene and they are making the effort. Combustion engineering is coming along as a third participant and even in the case of Foster-Wheeler, and they are good friends, I literally had to drag them into this technology. One of the reasons for it is because the question of patents. We have had about 8 or 9 basic patents and they are all in public domain. None of this work would have been possible without funding by DOE, EPA and OCR and while we may all complain about the way the Government operates, they were there in 1963 and 1964. In 1959 I approached two of the major boiler companies and two of the major coal producers. One of them was not Consolidation Coal. I was trying to raise \$10,000 to do some basic research on coal combustion. This is 1959, in an area I felt had been stagnant for at least 40 years, since pulverized coal came along and I couldn't raise \$10,000. I rolled up my plans and went ahead with normal activities because I had kids to feed. As a company we were very busy converting plants from coal to oil and gas. So really, all of the credit as far as funding and backup must go to DOE and ERD, EPA and the Office of Coal Research.

JOHN BELDING

Larry, did you have a rebuttal or whatever?

LARRY PAPAY

It wasn't a rebuttal, but the data that we did have on that chart is at a 1978 price level and it's based on a study which was done about 2 months ago, it is recent data.

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SESSION VIII

COAL TECHNOLOGY — GASIFICATION

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THE TEXACO COAL GASIFICATION PROCESS
FOR
MANUFACTURE OF MEDIUM BTU GAS

N79-27614

W. G. Schlinger

Texaco Inc.
Montebello Research Laboratory
Montebello, California

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ABSTRACT

The development of the Texaco Coal Gasification Process is discussed with particular emphasis on its close relationship to the fully commercialized Texaco Synthesis Gas Generation Process for residual oil gasification. The end uses of the product gas are covered, with special attention to electric power generation via combined cycle technology. Control of SO₂, NO_x and particulate emissions in the power generating mode is also covered. The application of this technology in a proposed Texaco-Southern California Edison demonstration project is mentioned. Investment information released by EPRI for a 1000-megawatt advanced combined cycle gasification facility, is also reviewed.

and carbon monoxide along with lesser amounts of carbon dioxide and methane. The reactants are introduced through a special burner into a refractory lined pressure vessel or generator and the auto-thermal non-catalytic reactions occur at temperatures ranging from 2,000-3,000°F. Small amounts of unconverted fuel or soot are recycled to extinction. The basic exothermic and endothermic chemical reactions are shown in Figure 1. Sulfur present in the fuel is converted to H₂S and small amounts of COS, and organic nitrogen is reduced to elemental nitrogen and ammonia. The hot exiting gases are cooled through appropriate heat recovery equipment and treated as necessary to produce the desired product.

I. INTRODUCTION

Medium BTU gas is usually considered to be a fuel composed primarily of hydrogen and carbon monoxide, with varying amounts of methane and inert components and a specific heat of combustion ranging from 250-500 BTU/SCF. This gas, particularly when produced at elevated pressure, can be processed by means of a variety of commercially proven technologies to remove sulfur compounds and produce a clean burning fuel or gas for use in many applications in which natural gas has been formerly employed. Some of these uses include fired process heaters, chemicals manufacture (ammonia, methanol, oxo-synthesis products), and gas turbine fuel.

III. COAL GASIFICATION

It was recognized nearly 30 years ago that fuel for the process could just as well be coal, and work on process development for production of synthesis gas from coal was then started at Texaco's Montebello Research Laboratory where Texaco operates a variety of large scale pilot plant units and gasifiers capable of processing 15-20 tons per day of coal. Economic incentives for using coal in place of petroleum products at that time were not very strong, and the process development proceeded on a low priority basis.

II. RESIDUAL OIL GASIFICATION

For many years, Texaco offered the Texaco Synthesis Gas Generation Process^{1,2} throughout the free world as an efficient technology for converting high sulfur residual petroleum fuels and tars to synthesis gas, approximately a 50-50 mixture of hydrogen and carbon monoxide. Some seventy plus plants have been built in the past twenty-five years. Most of these plants have been associated with manufacture of ammonia, methanol and oxo-chemicals.

In the late sixties, the solids gasification process finally evolved to its present form, and the energy crisis brought on by the 1973 Arab oil embargo greatly accelerated the development of the process based on coal as the fuel.

Basically, the process involves a slagging entrained downflow gasifier fed with oxygen and a concentrated slurry of ground coal in water. The same type of refractory lined gasifier is employed as in the earlier oil gasification process, except provision is made to remove solidified slag through a lock-hopper system. Optionally, the gasifier may be fed with a slurry of coal in oil and a controlled amount of reaction temperature moderator such as steam. Facilities for recycle of unconverted coal or char are also provided. A schematic flow diagram of the process is shown in Figure 2.

In a nut-shell, the process involves reacting the residual fuel with a controlled amount of high-purity oxygen and steam at pressures ranging from 300-1,200 psi with the net production of hydrogen

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The process is capable of efficiently gasifying a wide variety of caking and non-caking bituminous and sub-bituminous coals as well as lignites or brown coals and petroleum coke. In addition, the process has been used to demonstrate the gasification of a variety of residues from emerging coal liquefaction processes.

Due to the high gasification temperature, by-product tars, phenols, and hydrocarbons heavier than methane are not produced.

Slag removed from the screen below the lockhoppers consists of fused particles generally less than one-fourth to one-half inch in diameter. This inert material containing less than 0.5 percent carbon can be easily handled and removed to slag disposal sites. Typical slag removed from the pilot unit at Montebello is shown in Figure 3.

A. GAS PURIFICATION

The crude raw synthesis gas is first contacted with water at gasifier pressure to remove entrained particulates. Water removed from the scrubbing system is recovered through a settler where the particulate matter is extracted and recycled to the gasifier. After water contacting, the particulate loading in the raw gas is typically on the order of 1 Mg/Nm³. This washed gas is further cooled and treated for removal of undesirable acid gas components. The type of technology used in this step will be dictated by the final or end use of the synthesis gas. For example, if the gas is to be used as a gas turbine fuel, it is in the interest of overall process efficiency to remove only the H₂S and COS, leaving the CO₂ in the fuel gas to recover energy by expansion through the gas turbine. On the other hand, if synthesis gas for methanol, Fisher Tropsch synthesis or oxo-products is desired, sulfur compounds in the gas must be reduced to less than 1 ppm and all or substantial portions of the CO₂ will also need to be removed. Gas purified in this manner can also be used for manufacture of SNG.

Alternately, it may be desirable to reduce the ratio of CO to H₂ in the gas. This step can easily be done through the well-known water gas shift reaction. Generally, the shifting is carried out before the acid gas removal step using the sensible heat in the gasifier exit gases to reach the necessary steam content by direct water injection or quenching. This alternate makes it possible to produce high purity hydrogen for ammonia manufacture or use in coal liquefaction plants.

Various commercially proven acid gas removal processes are available for purifying the gas to the desired degree.

Typical compositions of some feed coals and coke and the raw synthesis gas from them are shown in Figure 4 and 5.

IV. POWER GENERATION

The above technology is particularly well suited to generation of electric power via coal gasification in the combined cycle system. Since sulfur is removed from the fuel gas before combustion in the turbine, SO₂ emissions can easily be maintained at or below mandated levels. The primary source of NO_x emission in fossil fuel-fired power plants is the organic nitrogen in the fuel. Since all organic nitrogen in the coal has been converted to elemental nitrogen and a small amount of ammonia which is removed in the water wash and subsequent processing, NO_x emissions are greatly reduced and are comparable to natural gas fueled systems.

Furthermore, it has been shown that specially designed burners or nozzles in the gas turbine can reduce NO_x emissions even further. Work in this area is presently underway at the Montebello Research Laboratory, as well as other installations.

V. DEMONSTRATION UNITS

In addition to the 15-ton per day pilot unit at Montebello, a 150-T/D unit is presently in the start-up phase in West Germany and the Tennessee Valley Authority is in the process of designing a 150-T/D unit for installation at Muscle Shoals, Alabama. Last March, Texaco and Southern California Edison jointly announced their intention to obtain partial support and to construct a 1,000-ton/day coal gasification combined cycle demonstration plant near Barstow in the high desert northeast of Los Angeles. Fuel gas from the coal gasifier will initially be used to fire an existing 65 MW boiler and eventually, when the combined cycle facilities are installed, the gas will be employed as turbine fuel producing a total of approximately 90 MW through steam and gas turbines. Preliminary engineering on this project is presently underway.

VI. ECONOMICS

The Electric Power Research Institute has recently published results of a study conducted by Fluor Engineers & Constructors, Inc. indicating that, with advanced turbine technology (2400°F expander inlet) the combined cycle system potentially offers one of the most attractive means yet available for gen-

erating electricity from coal in an environmentally acceptable manner. Heat rates are predicted to be below 9000 BTU/KWH and plant investment and other capital charges are estimated to be about \$800/KWH of capacity for a 1000 MW stand alone power plant. The study was based on mid-1976 dollars.

It is obvious that we have some interesting and difficult challenges ahead to merge the various technologies and to produce an efficient, smoothly running, environmentally acceptable power plant. This goal can be achieved.

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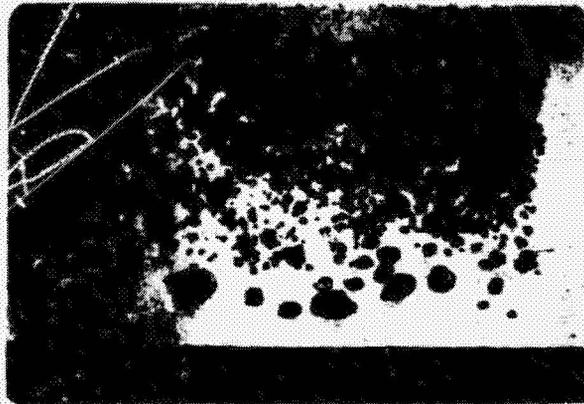
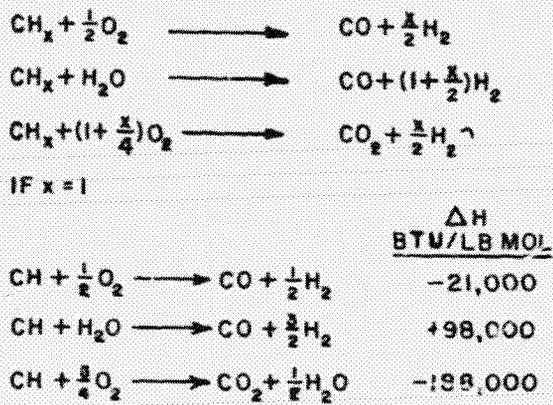


FIGURE 1. GASIFICATION: REACTION

FIGURE 3. SLAG REMOVED FROM GASIFIER

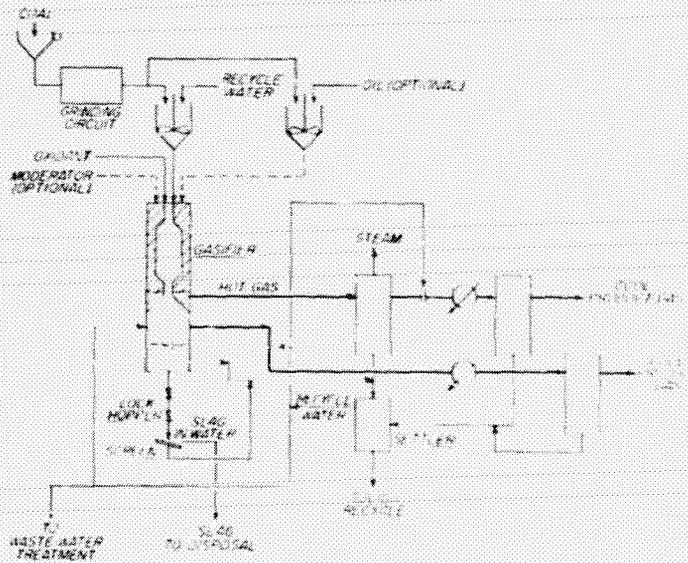


FIGURE 2. PILOT PLANT FLOW SHEET

<u>WEIGHT %</u>	<u>WESTERN BITUMINOUS COAL</u>	<u>DELAYED PETROLEUM COKE</u>	<u>EASTERN BITUMINOUS COAL</u>
C	74.56	89.47	67.62
H	5.31	3.71	5.16
S	0.46	1.44	3.26
N	0.99	2.69	1.00
O	11.47	2.37	11.17
ASH	7.20	0.31	11.76
HEAT OF COMBUSTION BTU/LB DRY	13,134	13,515	12,250

FIGURE 4. TYPICAL COAL AND COKE ANALYSES

<u>FEEDSTOCK</u>		<u>WESTERN BIT. COAL</u>	<u>DELAYED PET. COKE</u>	<u>EASTERN BIT. COAL</u>
OXIDANT SLURRY MEDIUM		OXYGEN WATER	OXYGEN WATER	OXYGEN WATER
PRODUCT GAS COMPOSITION, % VOL (DRY GAS BASIS):	H ₂	35.79	34.50	35.78
	CO	50.71	45.22	44.62
	CO ₂	13.14	19.38	17.97
	N ₂ -A	0.24	0.72	0.48
	CH ₄	0.09	—	0.08
	H ₂ S	0.02	0.13	1.02
	COS	0.01	—	0.05
HIGH HEATING VALUE, BTU/SCF (CO ₂ -H ₂ S- COS FREE BASIS)		321	319	320

FIGURE 5. TYPICAL GASIFICATION PERFORMANCE SUMMARIES

omit

INDUSTRIAL APPLICATION OF COAL DERIVED FUEL GAS

Gilbert V. McGurl

United States Department of Energy

Low BTU gas derived from coal is used in several industrial applications. A number of new projects are underway that will expand the range of uses of low BTU gas. Some of these are federally funded and others are entirely privately

funded. This paper reviews the state of the art in gasification systems, in gas cleanup systems, and in industrial application of low BTU gasification. A brief discussion of the economics of low BTU gasification will be included.

NOTE: The complete paper was not available at the time of publication.

N79-27615 ^{D18}

SYNTHETIC NATURAL GAS IN CALIFORNIA: WHEN AND WHY

W. B. Wood
Vice President

Southern California Gas Company
Los Angeles, California

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ABSTRACT

Western Gasification Company (WESCO) proposes to build and operate a coal gasification plant in northwestern New Mexico. The project would utilize coal to produce 257 MMCFD of pipeline quality gas (SNG) using the German Lurgi process. The SNG will be commingled with natural gas in existing pipelines for delivery to southern California and the Midwest. Cost of the plant is figured at more than \$1.4 billion in January 1978 dollars with a current inflation rate of \$255,000 for each day of delay. Plant start-up is now scheduled for 1984.

TEXT

Thank you for asking me to speak here today at this Department of Energy and California Energy Commission sponsored conference on coal use for California. The subject assigned me is "Synthetic Natural Gas in California: When and Why." Let me hasten to tell you that the "why" is an easier topic to deal with than the "when." The reason for the development of a synthetic fuel industry such as the proposed coal gasification plant in northwest New Mexico to supply synthetic gas (SNG) to southern California and the Midwest is threefold. Need. Technology is available. And economics.

As to need, I am quite sure everyone of you knows that there has been a decline since 1970 in the supplies of natural gas for southern California. Today we have about 75% of the gas supply that we had in 1970 for our 3.4 million customers in southern and central California. Yet we have a dependence on natural gas that is unmatched virtually anywhere else in the country. Nearly half of our non-transportation energy needs are met by natural gas, compared with only about a third for the rest of the country. Over 90% of our home heating and water heating is done with gas. And a full 40% of the commercial and industrial energy needs of California are met with gas.

The reasons for the decline in gas supply are falling production from California sources and declining mid-continent supplies with federal curtailments of the Gas Company's two major out-of-state sup-

pliers, El Paso Natural Gas Company and Transwestern Natural Gas Company.

Without additional primary supplies, curtailments could reach our Priority 1 customers who are homeowners and small businesses in 1984 in a cold year or 1986 in a year with average temperatures. Lowest priority customers who are the power plants and largest industrial users can expect little in the way of natural gas supply after this year lacking additional primary supplies. And between now and the mid-80s our remaining commercial and industrial customers who have standby fuel capability--usually oil--will experience increasing curtailments.

SNG from coal is one of the additional primary sources of supply we are now pursuing. Subsidiaries of Southern California Gas Company's parent company, Pacific Lighting Corporation, and Texas Eastern Corporation of Houston, Texas, have formed a joint venture, Western Gasification Company or WESCO, to build and operate a plant designed to chemically convert nearly ten million tons of coal per year into 250 million cubic feet per day of substitute natural gas, or SNG. The plant would be located in northwest New Mexico on the Navajo Reservation and would have cost more than 1.4 billion dollars, including financing costs, as of January 1, 1978.

The joint venturers have contracted with Utah International for the coal required for the first plant, with an option on coal for one additional plant. At the same time, Utah International will assign its existing water rights to WESCO for the water necessary to the gasification process.

The process to be used in the chemical conversion is one developed in Europe--the Lurgi process. The first section of the gasification process is the commercially proven Lurgi gas producer. The gas is produced by the reaction of coal and oxygen in the presence of excess steam at a pressure of 400 to 450 psig. The oxygen supplies the heat of reaction by combustion of the char which has not been gasified, while the steam is the essential source of hydrogen. The WESCO plant will have 24 gasifiers. The coal enters the gasifier through a coal

lock hopper in a batch sequence. A rotating grate distributes the fresh coal uniformly over the coal bed. As the coal moves down the reactor, it is successively preheated, dried, devolatilized, gasified and combusted. The resultant crude gas is then cooled and scrubbed to remove impurities.

At this point, the crude gas enters a shift conversion unit. In this step, carbon monoxide is catalytically converted to carbon dioxide and additional hydrogen is produced. The gas stream is now in the proper chemical balance for methanation.

Methanation is the step that catalytically converts the gas into essentially pure methane, or CH₄. Extensive laboratory and pilot plant testing of methanation has been completed by Lurgi and other companies including the joint venturers to WESCO. Although methanation has not been used in a commercial-size plant, it has been tested and proven in pilot plants. In fact, methanated gas produced in a demonstration plant in Westfield, Scotland, was introduced into the Scottish gas grid system for use in homes in and around the city of Fife. Lurgi and others are now ready to guarantee a commercial-size methanation unit.

After methanation, the gas undergoes dehydration and final CO₂ removal. The product SNG consists of 97% methane, with a heating value of 980 Btu's per standard cubic foot. The SNG is compressed to 1,000 psig and sent to market by existing pipeline systems. It is completely interchangeable and can be commingled with natural gas.

Other phases of the Lurgi process are designed to purify the SNG by removing by-products and to clean up plant emissions.

The chemical conversion of coal into synthetic gas offers several significant benefits. The gasification process provides a high efficiency of energy conversion. The thermal efficiency of the WESCO plant will be approximately 70%. The overall energy efficiency--from mine through ultimate residential user--is approximately 40% which by way of comparison is 1-1/4 times that of converting coal to electricity in a conventional power plant through the ultimate user. The SNG will move to market through existing pipelines, which provide one of the most efficient means of transporting energy now known. The recent decreases in the gas supply coming from traditional sources have resulted in existing pipeline systems not being utilized at maximum capacity. The WESCO plant output will augment such declining supplies and will flow through these under-utilized pipeline systems.

Reduced pollution is another advantage. In production of equivalent amounts of energy, pollutant emissions are significantly lower from the coal gasification process than from the combustion of coal. In the WESCO coal gasification plant about 15% of the coal will be burned to produce process steam, while the remaining 85% will be reacted chemically in closed pressurized vessels. In the generation of electricity, 100% of the coal is burned!

Finally, coal gasification offers a major new source of domestic energy, reducing reliance on foreign supplies, and causes no adverse impact on the U.S. balance of payments.

The second reason for the "why" of a synthetic fuel industry is, as I mentioned earlier, that commercial technology is available now. I am quite sure most of you are aware that there is considerable ongoing R and D for second generation coal gas technology. We, in fact, participate through the American Gas Association in that activity. The Lurgi process, however, is a commercially proven technology which has advanced through several stages of development since the early 1930s. Plants using Lurgi technology have been installed worldwide in Germany, England, South Africa, Korea, Pakistan and Australia. In fact, a new generation of gasifiers which are quite similar to those selected for the WESCO project are installed in the new Sasol II complex now under testing in South Africa. Although new technology promises greater cost benefits, possibly as much as 15% in another decade, from 15 to 17 years from now may be required to reach full commercialization and there is no way in view of today's inflationary and escalation rates that such plants can be cost competitive with a first generation plant which could be on line in 1984.

The third reason for the "why" that I mentioned is economics. Over the years, the natural gas consumer has had an economic advantage over consumers using other energy forms to meet heat energy needs. This advantage is expected to continue as synthetic gas from coal is introduced, particularly in those areas of the country where the only feasible alternative energy for residential, commercial, and small industrial customers is electricity. A coal-fired electric generating plant, together with necessary transmission and distribution facilities, requires from two to six times the capital investment required for a coal gasification plant delivering an equivalent energy output. The residential customer will have to pay at least twice as much for electrical energy produced by coal-fired steam electric generation as he would for gas energy produced by coal gasification. This cost differential is due to the

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lower thermal efficiency of electric generating plants, more expensive transmission and distribution facilities, and the high cost of meeting electric peak demands.

In California--and this is according to a published analysis made by the California Public Utilities Commission staff--the 1976 cost of energy delivered to the point of use from new nuclear or coal-fired electric generating facilities was over \$12 per million Btu's. By comparison, the cost of gas from the WESCO coal gasification project, using existing pipeline facilities for delivery to the point of use, was figured at about \$3 per million Btu's. That cost has escalated to \$4.16 in terms of January 1978 dollars. Costs related to coal-fired electric generation have experienced similar escalation. Even assuming the worst in terms of further delays and cost escalation, the cost of energy resulting from coal gasification should continue to have a substantial cost advantage, by comparison with the electric alternative, for the southern California gas consumers.

Please believe me it is not my intent here to promote coal gasification at the expense of coal-generated electricity. In fact, meeting our energy needs in southern California requires diligent development of all forms of energy plus, of course, conservation. Unfortunately, the complex benefits of new technologies such as coal gasification are difficult to grasp in the abstract, and comparisons are helpful.

You will recall I mentioned reduced pollution as one of the advantages of coal gasification. Comparisons are particularly striking when comparing the environmental impacts of two energy equivalent projects such as a coal gasification plant and a new power plant with scrubbers. The following data comes from a report prepared by the Radian Corporation for the Council on Environmental Quality and the Federal Energy Administration. In pounds per hour, particulates would be 180 from the coal gas plant and 1,070 from the power plant. SO₂ would be 450 compared to 4,300. NO_x, 1,780 compared to 20,830. CO, 90 compared to 1,200. Solid waste, 1,400 tons/day compared to 5,100. Finally, the water requirements would be 6,300 acre-feet/year compared to 54,300.

This brings me to the second part of my presentation--when can we expect a contribution by a synthetic fuel industry to our energy matrix. The proposed WESCO project is probably the front runner. Technically, it is essentially ready for construction. Major approvals have been received including a certification from the Federal Power Commission--now the Federal Energy Regulatory Commission--and the final environmental statement has been filed with the Council on Environmental

Quality. The State of New Mexico's Environmental Improvement Agency has issued permit authority to build the plant after being satisfied that the plant meets the State's very stringent regulations for emissions from a coal gas plant and that the plant would not exceed the Environmental Protection Agency's ambient air quality standards. Parenthetically, the only emission regulations existing for a coal gasification plant are New Mexico's. The EPA is currently working toward adoption of coal gas emission regulations. New Mexico's Surfacemining Commission has reviewed the mining operator's plan, Utah International, and issued a mining permit after being satisfied that the mining plan will return the mined area to at least equal to the existing grazing capacity as established for that area of the Navajo nation by the Bureau of Indian Affairs. Remaining hurdles to the WESCO project are development of a plan of financing and approval by the Navajo Tribal Council of a business site lease agreement.

The financing aspects of the project were considerably furthered when the President signed into law earlier this year the ERDA Authorization Bill for fiscal '78 which included language providing for a federal loan guarantee program for a coal gasification industry. The need for such a program results because of the large capital investment, coupled with the fact that there are no commercial-size high Btu coal gasification plants in operation. Potential lenders have concerns about a process that has not previously been used to produce the large volumes of SNG contemplated. But they are most concerned about government, regulatory or other force majeure actions which could delay construction, interrupt production or impair the flow of revenues required to pay interest and principal when due. Only the federal government can provide these assurances.

We believe lender protection can best take the form of a loan guarantee. Lacking loan guarantees, the net worth and income of Texas Eastern and ourselves, added together, simply does not provide sufficient credit base to convince lenders the loan would be paid off if we were unable to complete or operate the project.

Also, earlier this year, the Navajo Tribal Council voted down a proposed lease agreement. We are seeking, however, a reconsideration of the lease agreement by the Tribal Council, but that probably will not take place until after the Navajo nation elections which coincide with the federal elections in November.

The "when" then is more difficult to deal with because it remains somewhat nebulous, but the bottom line is that it will probably be 1984 at the earliest before a

coal gas plant is on line. At that time, three-fourths of the WESCO plant output of 250 million cubic feet per day of SNG would be delivered to the Southern California Gas Company and one-fourth to Cities Service Gas Company serving the Midwest. If the WESCO project should fall by the wayside, then one or more of others who follow not too far behind WESCO will likely be built, probably in the plains states of Montana, Wyoming, or the Dakotas.

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SESSION VIII: COAL TECHNOLOGY: GASIFICATION

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Session Cochairmen: Neal Cochran (DOE)
Ray Ryason (JPL)

Speakers: Warren Schlinger (Texaco, Inc.)
Lowell Miller (DOE)
Joe Byrnes (So. Calif. Gas Co.)

OPEN DISCUSSION BY ATTENDEES

LEONARD KELLER

I am from Methacoal Corporation of Dallas, Texas. I'd like to address the question to Mr. Byrne. We have talked for some time now, Methacoal Corporation to another Wesco Partner, about the future potentials of bringing by very economical means, a clean carbon fuel into the Los Angeles Areas for gasification, so that we could use sewage plant outflow water in the Los Angeles Area to make gas instead of destroying the tuna industry with that water which is incompatible with the marine environment. My question is, we sympathize with and know some of the problems you have gone through over the years in trying to keep the project going. We appreciate the manner in which you are doing it. The question is, having been through these throes once with the Wesco No. 1 Project, if Wesco elects to do the next phase in our way, which promises much better economics, we will encounter the same kind of beginning to end problems and time delays that you encountered in Wesco No. 1 or will the fact that you have gone through many of these trials and tribulations possibly make the road a little easier on second phase?

JOSEPH BYRNE

I'm afraid that's a mixed bag. Obviously, considering the things that we have done, we hope that we won't have to go back to square 1. However, any major changes in project as to location, financing or whatever, would impact on the FPC certificate, and we'd have to go back for a new certificate. Obviously the environmental statement that is in place with the Council on Environmental Quality calls for

a specific plant, at a specific site and we might have to go back through the lead agency, whichever that might be. It was the Department of Interior on the last project. Its really difficult to answer. It depends upon the magnitude of changes in the project.

I say we are looking off reservation. We're hopeful that we can locate close enough to where we are and yet off reservation. If we were to go that way it would require minor modifications to the environmental statement as now filed. We don't know that.

I would like to ask Dr. Schlinger if he would care to comment about a version of the Texaco gasifier incorporating the use of residual oil with the coal, rather than water or with a liquefaction variation of the Texaco gasifier.

WARREN SCHLINGER

I think that I just mentioned briefly in my paper that we had successfully demonstrated the ability of the gasifier to accept residues from the coal liquefaction processes, which we are going to hear about after the coffee break.

One of the interesting parts of this technology is that this is a way of supplying the hydrogen that is required for the coal liquefaction. This also makes it possible to gasify the heavy ends from liquefaction processes and use the gasified product directly for power generation, or even manufacture of LNG, if you wish. The light hydrocarbon material from the coal liquefaction can be used for manufacture of synthetic light petroleum hydrocarbons, portable fuels as you would call them, from automotive use, turbine fuel or something like that. There are many combinations of the two processes that are possible. I think that is just a matter of which is the most economic. You mentioned the possibility of making methanol from the gasified products. These are all viable. They have to be studied from an economic standpoint.

SESSION IX

COAL TECHNOLOGY — LIQUEFACTION

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OVERVIEW OF DOE COAL LIQUEFACTION PROGRAM

Jim Batchelor

United States Department of Energy

The DCE program on coal liquefaction exists to support the development of technology to commercial readiness for the conversion of coal to clean burning and marketable liquid fuels. In addition to the three major second-generation process development projects (which will be

reviewed following this paper), support is being given to promising third-generation processes, to needed ancillary processes, to advanced research, and to environmental and engineering studies. The content and relationship of the elements of the liquefaction program are discussed in this paper.

NOTE: The complete paper was not available at the time of publication.

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STATUS REPORT OF THE SRC-I AND SRC-II PROCESSES

George E. Chenoweth
Gulf Mineral Resources Co.
Denver, Colorado

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ABSTRACT

After sixteen years of bench-scale and pilot plant development, large solvent refined coal (SRC) demonstration plants are being planned which could lead to commercialization by the late 1980's.

I. BACKGROUND

Development of the solvent refined coal (SRC) process began in 1962 at Gulf Oil Corporation's Merriam, Kansas Research Laboratories and bench-scale work has continued at that location since that time. This work led to the construction and operation of a one-half ton per day pilot unit in 1964 which provided design data for a 50 tons per day pilot plant. Construction of the 50 tons per day Government-owned facility was completed in 1974 at Ft. Lewis, Washington and has been in operation since then. This extended research and development program has been funded by the U. S. Department of Energy (DoE) and its predecessors.

All work until 1973 was aimed at the development of a process to produce a low-ash, low-sulfur solid product known as SRC-I. In the SRC-I process, coal is slurried in a distilled, coal-derived, recycle solvent, mixed with hydrogen and reacted at high temperature and pressure. The reaction product is filtered to remove ash and unreacted coal which is further processed, such as by gasification, to convert it to an environmentally acceptable form for disposal. The filtrate is vacuum distilled to separate distillate from the "heavy" residual organic material which is removed and solidified as the solid SRC product. The distillate is further distilled to separate it into a recycle process solvent for the reaction area and limited quantities of fuel oil and naphtha. Much of the sulfur in the feed coal is converted to hydrogen sulfide which is recovered and converted to elemental sulfur.

By 1973, Merriam data had indicated a potential problem of insufficient production of the process solvent required for the reaction area. It was theorized that additional solvent production could be attained by recycling a portion of the reactor effluent slurry and utilizing it to replace some of the distilled solvent used to slurry the feed coal. This mode of operation increases the concentration of ash, and its catalytic components, as well as allowing the "heavy" (high molecular weight) organic material contained in the slurry to be subjected to further liquefaction reactions. The initial slurry recycle experiments

were successful in achieving the objective of increased solvent production. More importantly, though, indications were that replacing the distilled solvent completely with recycle slurry increased the degree of conversion of the "heavy" organic to distillate liquids to such an extent that a modification of the overall SRC process appeared feasible which would allow the elimination of the troublesome and costly filtration method of solids separation. Instead, solids separation from the reaction product would be accomplished in a much simpler and common commercial processing step -- vacuum flashing -- with the high solids "heavy" organic stream from the bottom of the vacuum flash drum being used as feed to a high pressure gasifier for production of the hydrogen required in the coal reaction area. Subsequent testing has demonstrated the viability of this SRC process modification which is now known as SRC-II. Its use results in the production of a liquid, rather than a solid, as the main product.

Simplified flowsheets of the SRC-I and SRC-II processes are shown in Figure 1. The major differences, as well as the similarities, readily can be seen.

II. FT. LEWIS SRC PILOT PLANT OPERATION

The largest SRC facility is the Government-owned and -funded pilot plant at Ft. Lewis, Washington. Construction was completed in 1974 at a cost of about \$21,000,000. It is staffed by 180 Gulf employees.

Since startup in 1974, the plant has enjoyed a high onstream factor. Its major accomplishments to date are:

1. Developed process yield data in both the SRC-I and SRC-II modes of operation sufficient for the design of much larger demonstration plants.
2. Identified process, mechanical, corrosion and erosion problems and determined solutions.
3. Produced solid SRC for small scale combustion tests and 3,000 tons for a large scale test which was completed in early 1977 at Georgia Power Company's Plant Mitchell near Albany, Georgia.

- Produced about 6,000 barrels of SRC-II fuel oil for a large scale combustion test in a commercial power plant which is scheduled to be conducted this summer. Its main objective is to determine if SRC-II fuel oil will meet the environmental requirements for a fuel for electrical power generation. Encouraging small scale combustion tests already have been performed.

Table 1 shows typical gross yields obtained during SRC-I and SRC-II testing at the Ft. Lewis Pilot Plant. Typical properties of the SRC-I solid and the SRC-II fuel oil produced for the large scale combustion tests are shown in Table 2.

One of the prime objectives in the Ft. Lewis Pilot Plant program for 1978 is to complete the installation and begin testing the Lummus Company's Solvent Deashing process to determine if it is a more viable method of solids separation than filtration.

The work performed at the Ft. Lewis Pilot Plant and the Merriam Laboratory is reported in quarterly, annual and interim Fossil Energy, U. S. Department of Energy, reports (Ref. 1, 2, 3, 4, 5).

III. OTHER SRC DEVELOPMENT

Since 1974, SRC-I process yield studies on several coals also have been conducted on a six-ton per day pilot plant at Wilsonville, Alabama. This plant is operated by Catalytic, Inc.; managed by Southern Company Services, Inc. and funded by Southern, Electric Power Research Institute and the U. S. Department of Energy. The Kerr-McGee Critical Solvent Deashing process will be tested there in 1978 to determine its viability as a method of solids separation.

In addition to the SRC-II development work at the Government-funded Merriam and Ft. Lewis facilities, extensive SRC-II yield studies have been conducted during the past two years with a Gulf-owned and -funded one-ton per day pilot plant at Gulf's Corporate Research Center, Harmarville, Pennsylvania.

IV. HEALTH PROTECTION AND ENVIRONMENTAL MONITORING PROGRAM

A worker health protection and environmental monitoring program has been in effect at the Ft. Lewis Pilot Plant since prior to its startup. It consists of:

- Periodic physical examination of workers.
- A worker industrial hygiene program.
- In-plant monitoring for potentially hazardous materials.

- Surrounding area monitoring.
- Toxicological test program with laboratory animals.
- A trace metals distribution study.

The findings from this overall program should prove to be beneficial in planning for larger SRC and other coal liquefaction plants. Detailed descriptions of the program and data obtained have been published in several Fossil Energy, U. S. Department of Energy, reports (Ref. 6, 7, 8).

V. SRC COMMERCIALIZATION

Gulf's initial SRC commercialization efforts occurred in 1974 when it provided process design support for the conceptual design of an SRC-I demonstration plant utilizing 2,000 tons per day of coal. The conceptual design was performed by Wheelabrator Clean Coal Corporation, utilizing Wheelabrator-Frye's Rust Engineering Co.

In 1975, Gulf decided to concentrate its commercialization efforts on the SRC-II process. Among its reasons for doing so were:

- Its concern with the many problems associated with filtration.
- Alternate methods of solids separation were at a relatively early stage of development.
- Its belief that SRC-II fuel oil would decrease the demand for imported oil while SRC-I solid product provided only an alternate to coal burning with stack gas scrubbing.
- Its belief that a liquid produced from coal had a greater variety of potential uses than a solid product and, thus, had more long term marketing potential.

In 1975, Gulf, utilizing the services of Stearns-Roger Inc., completed the conceptual design of an SRC-II demonstration plant with a coal feed rate of 6,000 tons per calendar day. In addition, a less detailed conceptual design of 30,000 tons per calendar day commercial plant was completed. Following extensive engineering studies in 1976, these conceptual designs were updated in 1977. Detailed engineering has begun on the demonstration plant and Gulf has proposed to the U. S. Department of Energy that the two parties jointly fund its design, construction and operation. It is being designed so that, after successful demonstration, it can be expanded to commercial size. Several eastern electric and gas utilities are interested in purchasing the products of this demonstration facility at a premium price in order to ensure the development of an alternate fuel supply. Other companies have proposed the design, construction and operation of solid

SRC-I demonstration plants to the U. S. Department of Energy.

The expected ranges of fuel products from Gulf's planned SRC-II Demonstration Plant are shown in Table 3. This product slate is based on minimizing electrical usage and utilizing naphtha and synthesis gas, in excess of that required for process hydrogen requirements, as plant fuel.

In conclusion, the publicly-owned SRC process has been developed over the last sixteen years to the point that demonstration with commercial-sized equipment can and should be conducted which could allow this process to make a contribution to the Nation's domestic "clean" energy production by the late 1980's.

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Table 1. Ft. Lewis SRC Pilot Plant typical yields, ^a wt. % of moisture free coal

	SRC-I	SRC-II
Carbon oxides	1	2
Hydrogen sulfide	1	2
Ammonia	-	1
Water	5	6
Methane - ethane	3	9
Propane - butane	2	5
Naphtha (Pentane - 350 ^o F)	5	8
Fuel oil (350 ^o F - 900 ^o F)	7	28
Organic vacuum bottoms (SRC)	62	27
Unreacted coal	6	6
Ash	10	10
Hydrogen	(2)	(4)

^aGross yields before hydrogen production and fuel requirements

Table 2. Typical properties of SRC-I solid and SRC-II fuel oil

	SRC-I Solid	SRC-II Fuel Oil
Composition, wt. %		
Carbon	87.2	86.5
Hydrogen	5.8	8.4
Nitrogen	2.1	1.1
Sulfur	0.75	0.25
Ash	0.15	0.02
Pour point, °F		-20
Flash point, °F		> 150
Melt point, °F	335	
Higher heating value, Btu/lb.	16,000	17,300

Table 3. Expected range of fuel products from planned SRC-II demonstration plant

	Per Stream Day
Fuel oil, barrels	10,000 - 12,000
IFG, barrels	3,000 - 4,000
SNG, MMSCF	38 - 46

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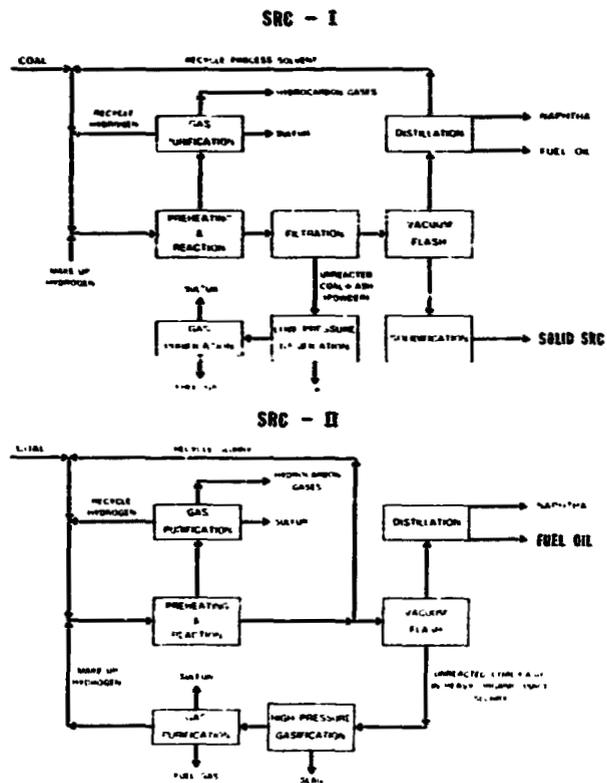


Fig. 1. Simplified SRC flowsheets

William C. Voss

Ashland Oil, Inc.
Ashland, Kentucky220
N79-27617

ABSTRACT

H-Coal is a catalytic process involving the direct hydrogenation of coal to produce hydrocarbon liquids. Its development was started in 1963 by Hydrocarbon Research, Inc., a subsidiary of Dynallectron. The process has operated at the bench scale level on a wide variety of coals including eastern U.S., western subbituminous and lignites from Texas and North Dakota as well as foreign coals. A three-ton per day process development unit has also been operated extensively, confirming bench scale results and adding substantially to the technical data base. The process affords wide flexibility of operation from "fuel oil" to "syncrude" modes.

A pilot plant now under construction at Catlettsburg, Kentucky is scheduled for completion March 31, 1979. It will be the largest coal liquefaction plant on-line in the U.S., processing up to 600 tpd of coal. Concurrent with the pilot plant, other development activities are being undertaken to provide timely initiation of a commercial project. Assuming successful operation of the pilot plant in 1979, engineering on a 50,000 BPD plant is scheduled to start in early 1980, construction in mid-1981 and operations beginning in late 1984.

I. INTRODUCTION

Recently Ashland has been studying commercialization of the H-Coal process and has had several meetings with Department of Energy personnel concerning such development. The discussion today will address both the status of the H-Coal pilot plant now under construction and the status of a proposal for commercialization of the process.

The pilot plant will be discussed later but just the scope of a project required for commercialization is large by any measure. An installation designed to produce 50,000 barrels per stream day of liquid products would require 18,500 tons per day of bituminous coal or 6,100,000 tons per year. Therefore, the facility would be the largest single point consumer of bituminous coal in the world, equivalent in fuel to a 2,300 MW power plant. It would require 3 relatively large underground coal mines to supply feed to one plant.

Obviously, much careful planning would be required to bring such an undertaking to fruition. Our most optimistic projections for a commercial plant would be on start-up in mid-1984 (as discussed later).

II. BACKGROUND

The H-Coal process developed by Hydrocarbon Research, Incorporated dates back to 1963. The process is a spin-off of the H-Oil technology which is a commercial system used for hydrogenation of residual oil.

H-Coal is a direct, catalytic hydrogenation of coal in an ebullating bed (boiling). The reactor operates at about 3000 psig and 850°F which are relatively severe conditions.

The basic experimental work on the process has been and is still being done on a bench scale unit and a pilot demonstration unit (PDU) at Trenton, NJ operated by HRI. The data base is large including 60,000 hours on the bench unit and 8,000 hours on the PDU. The process has been tested on a wide variety of coals from high volatile bituminous to lignites for domestic coals and on two foreign coals. This indicates the versatility of the processing, that is modifications can be made to accommodate markedly different feed coals.

In 1976 Ashland Synthetic Fuels, Inc., a wholly-owned subsidiary of Ashland Oil, Inc., was awarded the prime contract for construction and operation of an H-Coal pilot plant. Under terms of the contract, Hydrocarbon Research, Incorporated will supply technical advice and support throughout the program.

The plant, now under construction, is located across Interstate Highway 64 from Ashland's Catlettsburg, Kentucky refineries. The refinery will furnish hydrogen and other utility type commodities to the pilot plant which effectively reduces the total capital investment for the installation. The plant is near 40 percent mechanical completion and is a joint government-industry effort. The major portion of the funding for the project is from the Department of Energy. Industrial participants are as follows:

- Ashland Oil, Inc.
- Conoco Coal Development Company
- Mobil Oil Corporation
- Standard Oil (Indiana)

Additional funding is furnished by the Commonwealth of Kentucky and the Electric Power Research Institute, the research arm of the electric power generating industry.

The pilot plant is sized to process from 200 to 600 tons per day of coal, depending on the

reactor space velocity. That is, the "mode" of operation determines the capacity of plant as designed. Operating in "fuel oil" mode high space velocity, mild hydrogenation, fuel oil product, the capacity of the plant will be 600 tons per day. Operating in "syncrude" mode low space velocity deep hydrogenation, syncrude product, the capacity of the plant will be 200 tons per day.

The pilot plant is scheduled for mechanical completion March 31, 1979. Although it is a pilot plant, it will be the largest coal liquefaction plant ever built in this country. Since the pilot plant will be on-line next year, it should furnish sufficient data to allow early design and engineering of a commercial scale H-Coal plant.

III. PROCESS DESCRIPTION

A process description of a 50,000 barrel per day commercial plant is outlined in the following paragraphs and graphically presented in Figure 1.

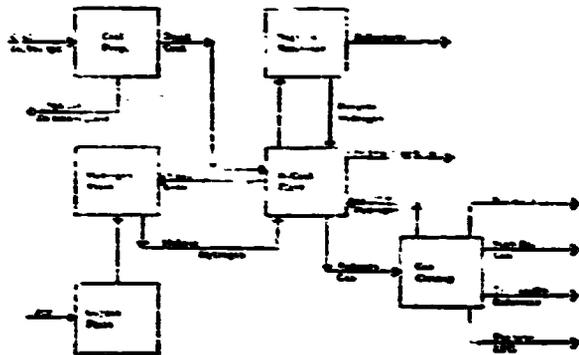


Figure 1. Block diagram, H-Coal process

A. COAL HANDLING AND PREPARATION

The run-of-mine coal is received at the plant and crushed to minus 3/4 inches in a hammer mill. From the mill the coal is fed through a transfer house to the coal storage pile, the steam plant, or crushed coal storage bins.

Coal from the bins is transported to a fluid bed drying system where the moisture content is reduced to about 2 percent by weight. The dried coal is then fed to a closed loop crushing system where the size is reduced to minus 14 mesh. The coal is then pneumatically conveyed to the slurry preparation feed bin.

B. HYDROGENATION PLANT

The coal is then mixed with recycle oil in the slurry mix tank. The recycle oil is made up of hydroclone overflow, fractionator bottoms, and some middle distillate from the fractionator. The mixed coal-oil slurry is then pumped to the reactor feed tank.

Each reactor is equipped with two direct-fired feed heaters, one of which heats the feed slurry and 50 percent of the makeup and recycle hydrogen and the second is used to heat the remaining hydrogen. From the slurry feed tanks the slurry is pumped to reaction pressure (about 3000 psig) and then is mixed with recycle hydrogen and heated to reaction temperature (about 850°F) before entering the reactor. The other hydrogen (not mixed with the slurry) is also heated to 850°F prior to introduction to the reactor. The dual heater arrangement offers excellent temperature control of the feed streams. The mixing of recycle hydrogen and slurry before heating is advantageous because the hydrogen lowers the slurry viscosity and improves heat transfer.

The charge in the reactor is maintained in an ebullated state (boiling action) by an internal liquid recycle. This assures adequate catalyst contact and facilitates catalyst addition and withdrawal during operation.

The products from the reactor are taken overhead and sent to the primary separator where the light products are flashed off and the oil, unconverted carbon, and ash flow through a pressure hold-down valve to a high pressure flash drum operating at 1200 psig. The light gases and oils overhead are heat exchanged with the makeup and recycle hydrogen and cooled and flashed in a series of drums, each operating at lower pressures and temperatures than the preceding one to recover unreacted hydrogen for recycle back to the reactor. The gases and light oils recovered during the flashing are sent to gas cleanup and fractionation respectively.

The heavy oil, unconverted carbon, and ash stream from the bottom of the primary separator is also flashed in a series of drums to separate oil and gases from the heavy residue. The gases and oil recovered are again sent to gas cleanup and fractionation respectively. The heavy fraction containing almost all the unconverted carbon and ash flows to hydroclone for a partial concentration of the solids into the underflow stream. The hydroclone overflow is recycled to slurry preparation and the underflow flows to the atmospheric and vacuum towers operating in series which concentrate the solids. The oils recovered from the towers are sent to fractionation and the bottoms from the vacuum tower are used for feed to the partial oxidation gasifiers in the hydrogen plant.

The fractionator separates the plant into various fractions, gases, naphtha, light oil, and bottoms. The gases flow to the gas cleanup system, the naphtha is stabilized and sent to storage, the light oil represents distillate fuel oil product and the bottoms from the fractionator, along with some of the light oil, are recycled to slurry preparation.

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The foregoing description is based on the "syncrude" mode of operation. However, it should be noted that the H-Coal process does afford flexibility as to product distribution and may indeed be operated in a "fuel oil" mode. It follows that some of the processing described above would require modification for the "fuel oil" mode of operation.

C. NAPHTHA REFORMING

The processing proposed by Ashland for a commercial plant includes reforming of the highly naphthenic naphtha to form an aromatic gasoline blending reformat. The hydrogen produced by dehydrogenation of the naphthenes will be recycled to the H-Coal reactor; this effectively reduces the size of the hydrogen plant as well as increases the value of the product.

At this time, we have assumed that the phenols can be tied to the reformer guard case. If this proves to be unacceptable, the phenols could be removed prior to reforming. The research octane number of the reformat is estimated to be 101.

The guard cases will use a nickel-moly catalyst to reduce both the sulfur and nitrogen concentrations to acceptable levels for the platinum-type reformer catalyst. The reforming would be relatively mild because of the highly naphthenic feedstock which would not require isomerization or hydrocracking to form a desirable gasoline blending stock.

D. GAS CLEANUP AND COMPRESSION

The refinery-type gases collected from the hydrogenation system are mixed and compressed to 215 psig and flow to a light oil wash where all of the naphtha and much of the butane entrained in the gas streams are recovered. The gases from the light oil absorber are compressed to 600 psig and flow to the hot potassium carbonate (Benfield) acid-gas scrubbing system for removal of H₂S and CO₂. Trace quantities of CO₂ and H₂O are removed by molecular sieves prior to the cryogenic cold box. The cryogenic system produces a hydrogen recycle stream (95% purity), a fuel gas stream, and a mixture of propane and butane. The propane and butane are separated into the final products in a debutanizer.

The naphtha from light oil stripping is sent to naphtha reforming and the butane is taken as gasoline blending stock. The acid gas from the Benfield regenerators flows to a Claus unit. The cryogenic fuel gas stream is compressed for pipeline transmission, the propane is sent to the LFG product, and the hydrogen is compressed and recycled to the hydrogenation plant.

E. THE HYDROGEN PLANT

The gasification system presently contemplated will be based on the Texaco partial oxidation system. Vacuum tower bottoms or other more concentrated resid from the H-Coal process will be used for feed and supplemented as necessary with coal to meet the hydrogen requirement. The heavy liquid bottoms and coal have each been tested successfully by Texaco in pilot plant operations. This type unit is being considered for both high Btu gas plants and methanol plants now under investigation so design data is likely to be available in time for H-Coal development.

Every effort will be made to maximize the solids content of the H-Coal resid prior to gasification. Any reduction in oil content will be replaced by coal at a significant economic advantage. Several ongoing projects are focusing on solids-liquid separation and should provide technical and economic data within a time frame compatible with the proposed H-Coal schedule.

The hydrogen plant, after synthesis gas generation, is a conventional processing system for hydrogen production. That is, two stages each of shifting and acid-gas scrubbing to get 95% plus purity product.

The gasification system, including the supporting oxygen plant and the substantial steam requirement, is an expensive part of the total plant, both from an operating and capital cost consideration.

There are no gasifiers in operation today in the world of the size proposed here but much development work on such units has been done and it appears feasible to build such a unit.

F. SUPPORTING PLANTS AND TANKAGE

All of the processing required for hydrogen, sulfide recovery and sulfur manufacture, ammonia recovery and tankage are of conventional design and afford no unique problems as applied to H-Coal processing.

IV. IN-HOUSE COMMERCIAL PLANT STUDY

The foregoing process description was based on an in-house Ashland study for commercialization of the H-Coal process operating in the "syncrude" mode to produce about 60,000 barrels per day of liquid products.

The processing as visualized produces salable products and ash. The system produces no heavy oil (boiling above 600°F) because it is recycled to extraction or comes off the bottom of

the vacuum towers mixed with the ash and unconverted carbon. The vacuum tower bottoms are fed to the partial oxidation unit for synthesis gas production and subsequent hydrogen manufacture. The result is a plant that produces commercial products and ash, an important feature of the processing worked out at Ashland.

The commercial plant is sized to process 18,541 tons per day of "as received" coal to produce 49,741 barrels per day of hydrocarbon liquids, 29.52MM standard cubic feet per day of high Btu gas, 567.5 long tons per day of sulfur, and 118.8 tons per day of anhydrous ammonia. The coal requirement and product slate are shown in the following slide:

Table I. Product slate - commercial plant

Coal Required "As Received"	18,541 tpd
Products	
Reformate	15,182 BPD
Distillate (400-609°F)	27,792 BPD
Butane	3,276 BPD
Propane, LPG	3,491 BPD
Total	49,741 BPD
By Products	
Sulfur	567.5 LT/D
Ammonia	118.8 ST/D
High Btu Gas	29.5 MMscfd

V. ECONOMIC EVALUATION

An economic study of the commercial plant, sized as described previously, has been completed by Ashland.

"The state of the art" of coal liquefaction dictates that an economic evaluation at this time be of a preliminary nature. That is, our evaluation is based on a "factored" type estimate. This type estimate requires materials and energy balances on the flow sheets, preliminary engineering, sizing and costing of major equipment items but piping, structures, instruments, etc. are taken as a percentage of the bare equipment costs and thus arriving at a total installed capital cost.

Our primary interest at Ashland has been the syn-gas mode of operation and our economic projections have been made on a plant operating in this mode only.

Obviously, economic projections require the preparation of schedules and Figure 2 is a phased schedule for commercial development of the "total process". The preliminary engineering and cost estimate is being initiated now and should be completed by the end of March 1979. Also, concurrently, preliminary site selection work is under way with particular emphasis on Illinois basin reserves as possible feed for the first

H-Coal commercial plant. Ashland is actively seeking out partners to form a consortium for industrial support of the commercial project. Initial environmental work is being done in that the scope and nature of work required is being planned and defined leading to an environmental assessment which is required for an impact statement. Also during Phase I, permit requirements will be determined and defined so that an action plan for acquisition of same can be instigated.

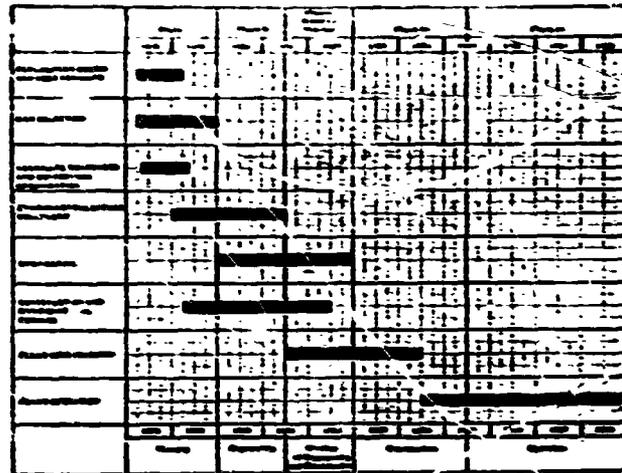


Figure 2. H-Coal commercialization schedule

Phase II starts in January 1980 when commitment is made to plant engineering. Plant engineering includes detailed plant engineering, preparation of equipment specifications, preparation of a construction bid package, and selection of an erection contractor. Environmental studies will be continued through the first half of the engineering phase culminating in the approval of the environmental impact statement in mid-1981. Then Phases II and III would overlap as engineering would extend into the construction phase.

Phase III construction would start in mid-1981 and extend to mid-1984 (3 years). This is an ambitious schedule for such a large complex plant and will require meticulous planning to maintain.

A concise statement of work will be prepared discussing in detail the work to be accomplished by the construction contractor. A complete construction schedule will be prepared, including a "Critical Path Model" so as to assure procurement and logistics can be adequately planned and coordinated.

The schedule will include all on-site activities from site preparation to mechanical completion including milestones which are important construction goals and which will allow evaluation of the project at instances of attainment.

Phase IV will be the start-up and operation of the plant.

**REPRODUCIBILITY OF THE
ORIGINAL DATA**

The economic projections shown in Table 2 assumes 75 percent debt, 25 percent equity capital, with the discounted cash flow rate of return on equity only. The interest on debt is taken at 8.75 percent or 1 percent above the prime interest rate.

The operating costs are determined using \$20 per ton for coal and normal coating procedures to arrive at a total estimated annual operating cost.

The by product credits taken were sulfur at \$25 per ton, high Btu gas at \$2 per million Btu's, and ammonia at \$110 per ton.

The projections were made using constant 1977 dollars and projected current dollars for capital determination.

The DCF ROI was based on the value of products listed previously corrected for entitlements which gave an average value of the liquid products at \$16.50 per barrel. If the values were not corrected for entitlements the product values would be \$14.02 per barrel.

The DCF ROI was then calculated three ways: first using constant dollars, secondly inflated to start-up only, and thirdly using full inflation.

Table 3 shows the identical sets of numbers on a 100 percent equity capital base. Obviously, high debt has a profound effect on DCF ROI.

Table 2. Commercial plant

Economic Projections		
Capital Investment	1977 Dollars	Current Dollars
Total	582.7	896.0
Debt	453.6	700.2
Equity	125.2	265.2

Equity DCF ROI	
Constant Dollars	14.8%
Inflated to Start-up	17.9%
Full Inflation	31.8%

Table 3. Commercial plant

Economic Projections		
Capital Investment	1977 Dollars	Current Dollars
Total	582.6	896.0

Project DCF ROI	
Constant Dollars	9.1%
Inflated to Start-up	10.5%
Full Inflation	19.8%

The next table shows the inflation rates used in the preceding economic analysis. Making such prognostications has been a precarious occupation in recent history but extended forecasting requires some predictions of inflation rates.

Table 4. Projected inflation rates

Year	Crude Oil Price (Product Value)	Coal Price	General Inflation	Construction Inflation
1977-1979	4.6%	6.6%	4.6%	6.9%
1980-1984	7.0	5.0	5.0	7.0
1985-1989	10.0	4.0	4.0	
1990-1994	7.0	4.0	4.0	
1995-2005	2.0	1.0	1.0	

It is obvious from the above that Ashland contends that oil prices will begin to escalate more rapidly than either coal prices or general inflation in 1980 and continue at a more rapid inflation rate through 1994. Therefore, applying the above inflation rates to a coal based synfuels plant improves the economics over a constant dollar case as was indicated in the tables.

VI. GOVERNMENT SUPPORT

When one considers the constant dollar economics which are marginal, the projected capital intensiveness of the proposed project one must conclude that development by the industrial community without economic incentives from the government are unlikely. In fact, action will be required in both the economic sector and the environmental area if an accelerated schedule is to be maintained.

The economic incentives which have been suggested include guaranteed non-recourse government loans with various industrial buy-back provisions, accelerated investment tax credits, tax credit allowance for each barrel of product, government grants for the initial development, and combinations of the above. It will be necessary in any event to require sufficient funding from the industrial consortium to indicate their commitment to the success of the project.

To meet the schedule outlined previously, unreasonable delays must be eliminated from the environmental program which is on the critical path. Obviously, one can not commit to construction without reasonable assurance that the environmental impact statement is acceptable. Since an environmental assessment is required for the preparation of an EIS, any unusual delays would extend the schedule because of time requirements for baseline data and other time constraints inherent in the assessment work.

VII. SUMMARY AND CONCLUSIONS

1. We believe at Ashland that coal liquefaction development in the United States is inevitable.
2. The H-Coal program is underway now and should be accelerated.
3. We are now preparing a formal proposal to the Department of Energy for H-Coal development.

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EXXON DONOR SOLVENT COAL LIQUEFACTION PROCESS

N79-27618

W. R. Epperly
L. E. Swabb, Jr.
J. W. Taunton

Exxon Research and Engineering Company
Florham Park, New Jersey

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ABSTRACT

Exxon Research and Engineering is developing a donor solvent coal liquefaction process to produce low-sulfur liquid products from a wide range of coals. The primary goal is to achieve a state of commercial readiness by 1982 through an integrated program of laboratory and engineering research and development in conjunction with operation of a 250 T/D pilot plant. This presentation will discuss the basis for this development project and the status of the program.

INTRODUCTION

Exxon has been doing research on coal liquefaction for eleven years. Early in the program many different approaches to liquefying coal were explored and tested. The goal was to define a process that would be reliable and operable on many different kinds of coal, and that would have a high probability for successful development. By late 1973 the Exxon Donor Solvent (EDS) process was defined and early in 1974 an aggressive research and development program was launched to bring the EDS process to commercial readiness. Since January 1976 the project has been jointly funded by Exxon, the Electric Power Research Institute, Atlantic Richfield Company, Phillips Petroleum Company, and the U.S. Department of Energy.

EDS PROJECT GOALS

The goal of the EDS coal liquefaction project is to develop the process to a state of commercial readiness, i.e., the technology will be available at the end of the project to design and build a full-scale, pioneer commercial plant with a reasonable and acceptable level of risk. The term "commercial readiness" has broad implications and for a new technology such as coal liquefaction depends on a number of factors. These factors include the nature of the new technology, the assessment of alternate development routes, the technical capability of the organization that will design the pioneer commercial plant, the level of risk in the pioneer plant that is acceptable to the owner, and the incentive for early commercialization. The evaluation of these factors, in combination with one another, will determine the likelihood of reaching commercial readiness for this particular technology.

EDS PROCESS DESCRIPTION

The EDS process is illustrated schematically in Fig. 1. The feed coal is crushed, dried, and slurried with hydrogenated recycle solvent (the donor solvent) and fed to the liquefaction reactor in admixture with gaseous hydrogen. The reactor design is relatively simple: an upward plus flow design operating at moderate conditions of 800-900°F and about 2000 psi total pressure. The reactor effluent is separated by a series of conventional distillation steps into a recycle solvent depleted of its donor hydrogen, light hydrocarbon gases, C₁-1000°F distillate, and a heavy vacuum bottoms stream containing 1000°F liquids, unconverted coal, and coal mineral matter. The spent recycle solvent is catalytically hydrogenated in a conventional fixed bed catalytic reactor. The light hydrocarbon gases are steam reformed to produce the necessary process hydrogen.

The heavy vacuum bottoms stream is fed to a FLEXICOKING[®] unit along with air and steam to produce additional distilled liquid products and a low Btu fuel gas. This fuel gas is used in the furnaces required to operate the process. FLEXICOKING is a commercial petroleum process that employs an integrated coking/gasification sequence in circulating fluidized beds. In this process, the unit is operated at low pressure (100 psi) and intermediate temperatures (900-1,100°F in the coker and 1500-1800°F in the gasifier). Essentially all organic material in the vacuum bottoms fed to FLEXICOKING is recovered as liquid product or combustible gases. Residual carbon is rejected with the ash from the gasifier fluidized bed.

The EDS process has a number of distinct features. The process steps are based on demonstrated petroleum technology where applicable, and are manageable and uncomplicated. The noncatalytic liquefaction and catalytic hydrogenation steps are separated. As a result the hydrogenation catalyst is exposed to only distillate coal liquids. This results in very low catalyst deactivation rates and also allows direct control of the amount of hydrogen actually added to the coal through the donor solvent. The use of a properly tailored donor solvent has substantial benefits in process operability and product quality.

* "Service Mark"

Distillation to separate liquefaction products is the most cost effective method and provides direct control over the properties of the separated streams. This control is of critical importance when pumping high viscosity vacuum bottoms streams to the FLEXICOKING unit.

EDS PRODUCT DISTRIBUTION

The products from liquefying Illinois bituminous coal are shown in Fig. 2. One ton of dry bituminous coal will yield 2.6 barrels of liquid products--0.1 barrel of LPG, a barrel of naphtha and 1.5 barrels of fuel oil. These yields are in keeping with the constraint of carbon balance to produce process fuel and hydrogen. The naphtha is a good feedstock for gasoline production and the fuel oil can be used in stationary turbines for peak shaving generation of electric power and as heating oil and boiler fuel. The process also produces 78 pounds of sulfur, 12 pounds of ammonia and 223 pounds of ash per ton of coal feed.

PROJECT FEATURES INTEGRATED R&D PROGRAM

The EDS project features an integrated R&D program involving bench scale research and a number of pilot plants of different sizes. Fig. 3 illustrates the reproducibility of the data. Liquefaction distillate liquid yields (expressed as weight percent of dry feed coal) is plotted against the residence time of the slurry in the liquefaction reactor. The data are for Illinois #6 coal at 840°F and 1500 psi hydrogen partial pressure. Each of the data points represents an average of four 24-hour balance periods of steady-state operation at the indicated conditions and with material balances of 98 to 102%. The solid line represents a least squares fit of the data from the 100 pound per day pilot plant. Data from the 1 ton per day pilot plant agree with this correlation. The dashed line is from a liquefaction kinetic model based on different levels of reactivity for different coal macerals tied together by a network of coupled chemical reactions. The agreement with the experimental data is excellent. In addition to reproducing these data for Illinois coal very well, the kinetic model is also valid for describing the liquefaction of a Wyoming subbituminous coal. The use of a kinetic model and the high quality of confirmatory data obtained from two considerably different size pilot plants leads to a high level of confidence in predicting the yields in the 250 ton per day pilot plant, which is now being built.

The 250 ton per day pilot plant is an important part of the integrated program. The size of the pilot plant was minimized while maintaining consistency with commercial plant scale-up practices in the petroleum industry. Coking in the slurry preheater, flow distribution and stability in the liquefaction reactor, and coking

and entrainment in the vacuum distillation step were identified as critical areas. Satisfying engineering scale-up and operability criteria for these areas determined the size of the unit. The design basis for the 250 ton per day unit has been confirmed from operations of the one ton per day pilot plant and this gives us added confidence in the successful operations of the larger unit.

Actual operations of the 250 ton per day unit, which will begin in late 1979, will be aimed at confirming engineering scale-up criteria, determining the reliability of the preferred operation conditions, defining practical operating limits for various process steps, and determining operating procedures in critical process areas to allow smooth start-ups, shutdowns, and transitions from one mode of operation to another. To achieve these objectives, the unit was designed with flexibility to accommodate 20 alternate modes of operation such as different coal feeds, different liquefaction reactor configurations and different coal concentrations. Analyses of the 250 ton per day pilot plant operations will provide an important part of the basis for a commercial plant design.

PROJECT STATUS

The present status of the EDS project can be summarized as follows:

(1) The feasibility of basic process steps has been confirmed in laboratory studies in which over 30,000 hours of pilot unit operation have been logged. Liquefaction conditions for Illinois and Wyoming coals have been successfully defined in pilot plants processing both 100 pounds per day and one ton per day. In addition, the liquefaction conditions for two different lignites have been defined in the 100 pound per day pilot plant. These studies have investigated variations in reactor temperature, pressure, residence time, treat gas rates and composition, and solvent composition.

(2) The FLEXICOKING process step has been successfully operated on vacuum bottoms from Illinois coal in a two barrel per day pilot plant. Operations are now in progress with vacuum bottoms from Wyoming coal. This scale of operations parallels studies used in the commercial development of FLEXICOKING for petroleum residua.

(3) Flexibility to vary the product distribution by changing severity in the liquefaction reactor has been established. For example, the ratio of C₄ - 350°F naphtha to 350°F+ fuel oil has been varied from 0.3 to 1.3.

(4) Engineering studies utilizing results from operations of the one ton per day pilot plant have confirmed the criti-

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cal design basis for the 250 ton per day pilot plant.

(5) Comprehensive commercial plant study designs, involving 10 engineer years of effort, for Illinois and Wyoming coals, have been completed. These studies incorporated the latest laboratory data defining the process steps and included provisions for coal preparation, steam, fuel gas and power generation and product recovery. In addition, correlations have been developed which relate process results to operating conditions and economic models have been developed to select optimum plant configuration and to predict commercial plant economics. These correlations and models allow us to study the effect of process conditions on commercial plant investment and operating cost.

(6) Product utilization studies are in progress to define the preferred commercial outlets and the trade-offs, if any, which will be necessary to insure effective use. This work has primarily focused on end use testing, incorporation of product into existing fuel outlets, and product hydrotreating at different conditions. The coal naphtha is projected to make excellent gasoline components after catalytic reforming, and the 350°F to 1000°F and 350°F+ liquids meet current ASTM specifications for No. 4 and No. 6 fuel oils. Combustion testing in commercial equipment has been encouraging from the standpoint of the completeness of fuel combustion. In addition, existing particulate emission standards were met without mechanical modifications to the equipment.

In conclusion, the outlook for successful development of the EDS process is excellent and small commercial plants could be on-stream in the late 1980's, assuming that adequate commercial incentives exist.

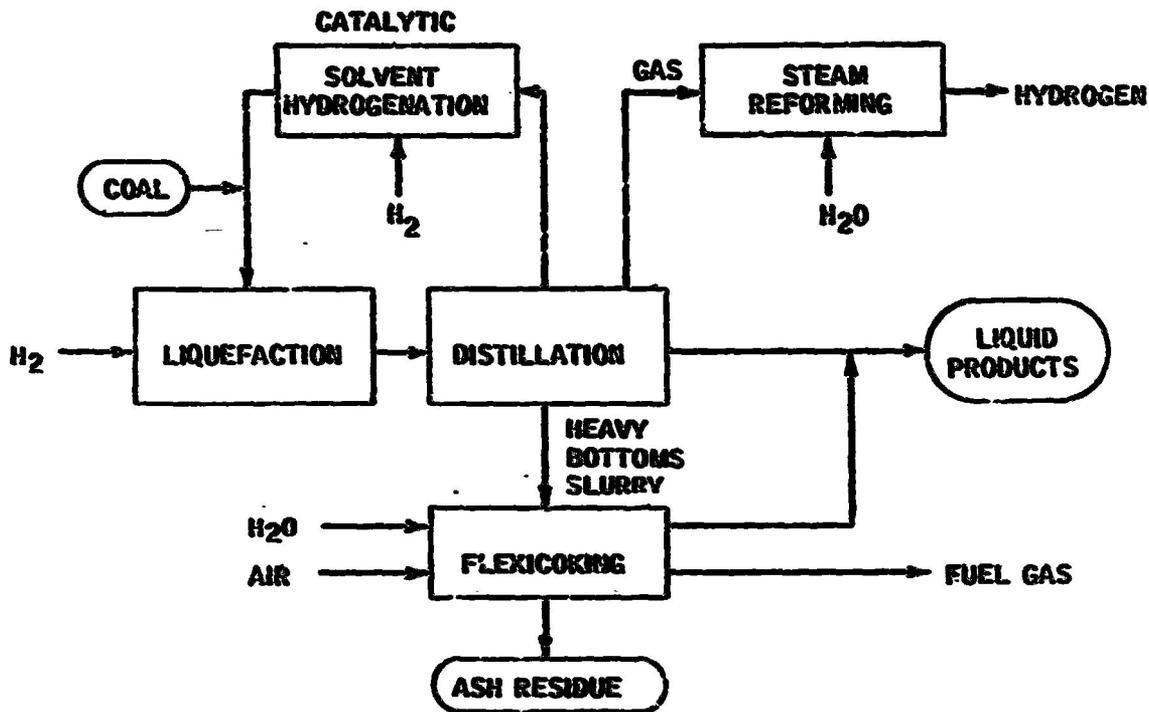


Fig. 1. Exxon Donor Solvent EDS Process

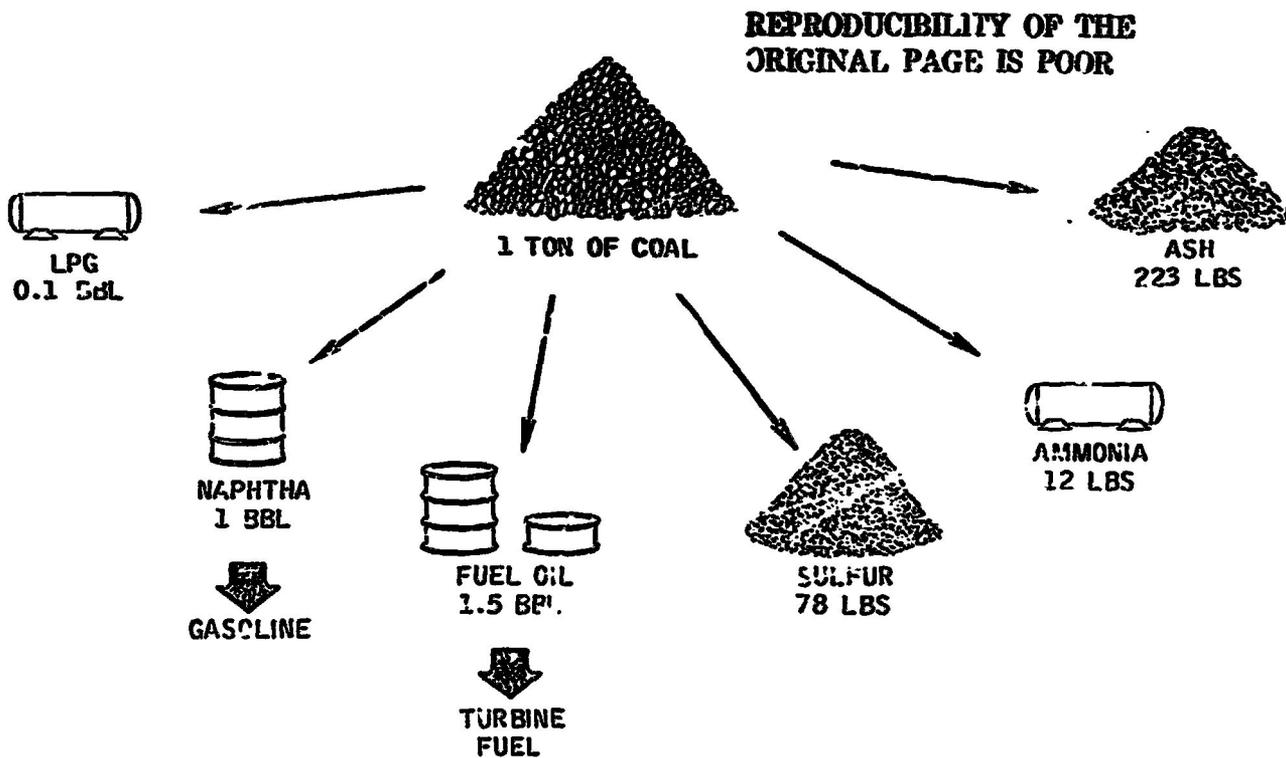


Fig. 2. Products from Bituminous Coal

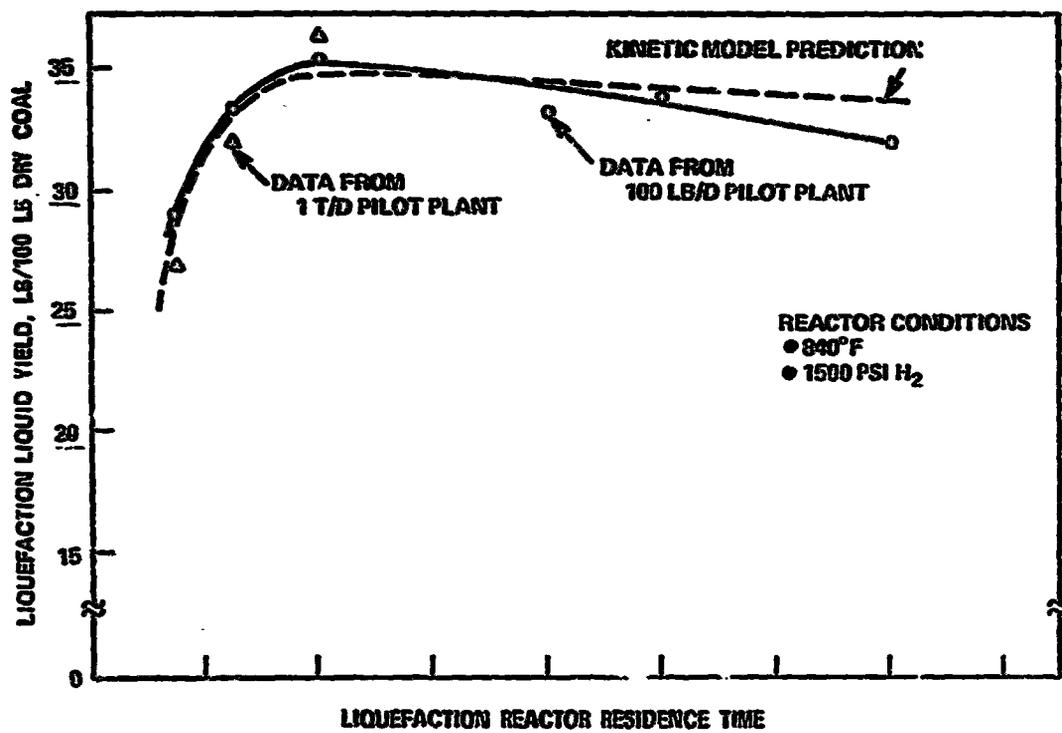


Fig. 3. Liquefactio. Liquid Yields for Illinois Coal

D22

METHANOL FROM COAL

Donald R. Miller
President
Vulcan Cincinnati, Inc.
Cincinnati, Ohio

N79-27619

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ABSTRACT

Methanol or methyl fuel can be produced from coal using today's existing technology at prices equal to or less than other synthetic fuels on a cost per million Btu basis.

It has desirable properties from environmental, safety, toxicity, transportation, storage, ease of burning, and retrofitting of present boilers.

Its use as a boiler fuel has been tested in a public utility boiler with good results. Its use as a turbine fuel has been tested successfully. Automobiles are operating successfully.

It can be made in great quantities from domestic coal or lignite sources, providing vast reserves, and be a factor in this country's striving for self-sufficiency in energy.

Crushed coal may be slurried in methyl fuel rather than water and piped to the using installation from the mine-plant.

1. INTRODUCTION

The intensity of the energy and international balance of payments crisis and the need for more pollution-free forms of energy have forced attention to methods of producing synthetic fuels from coal. A number of the earlier papers have discussed technology in various stages of development rather than using presently available technology. The production of methyl fuel or fuel grade methanol, a mixture principally of methanol together with coproduced controllable percentages of higher alcohols, by gasification of coal to synthesis gas followed by catalytic conversion to methyl fuel, is one of the most promising routes available for the immediate production of a clean synthetic liquid fuel from coal.

Please note that I have a small burner operating on methyl fuel. Note the cleanliness and simplicity of burning.

Listing a set of criteria to which a synthetic fuel should conform to improve upon today's energy and environmental problems, one would include the following:

It should be environmentally clean burning in SO₂, NO_x, CO, hydrocarbons and particulate emissions and produce no ash for disposal.

It should be easy to transport, store in quantity and burn.

It should not pose new safety hazards or undue toxicities.

It should be burnable with only minor boiler retrofit expense.

It should be flexible so as to be burned in boilers, turbines, automobiles or diesels.

It should be available from domestic sources from essentially inexhaustible supplies of feedstock.

It should be available in quantity at costs equal to or less than other synthetic liquids or gases on a dollars per million Btu basis.

Finally, its technology must be available today, not awaiting further pilot plants, demonstration plants and other endless hurdles which seem to plague other synthetic fuels and on which inflation keeps taking its toll.

If one applies these realistic criteria to a fuel, then one may conclude that methanol, methyl fuel, is an answer.

A test undertaken by Vulcan Cincinnati, Inc., employees which involved turbine suppliers, boiler designers and burner manufacturers, did not reveal any substantive doubts regarding the use of methyl fuel as a fuel for stationary power facilities and gas turbines.

Major utilities we had spoken with had expressed great interest in obtaining fuel at the projected costs, but had deferred firm commitments because methanol had not been used in this way before. Therefore, a small-scale demonstration test of methanol combustion was conducted at the facilities of Coen Company, Burlingame, California, on a boiler test stand used for fuel and burner evaluations. The results of these tests are given in Table 1.

A larger scale demonstration was then carried out in cooperation with a number of utilities and other companies, including Southern California Edison, Consolidate Edison (New York), New Orleans Public Service, and twenty-four other organizations.

A boiler operated by New Orleans Public Service, Inc., was selected for the demonstration. This unit is a Babcock & Wilcox boiler with a rated capacity of 425,000 lb/hr steam and a net summer capability of 45 Mw. It is a balanced draft boiler with flue gas bypass for control of superheat and is equipped with six burners.

Table 1. Methanol Compared to Natural Gas and No. 6 Oil

	Methanol	Natural Gas	No. 6 Oil
Lb Fuel/MM Btu	102	42	54
Lb Stoic Air/MM Btu	686	723	756
Lb Flue Gas/MM. Btu	788	765	760
NO _x Emission/Equivalent Flue Gas	25-50	30-200	350

Methyl fuel firing of the boiler required only that a centrifugal pump be installed in parallel with the existing pumps, with a recirculating line from discharge to suction for start-up. No other changes were made except to change nozzle tips to B&W's 85 degree Y-type.

Fuel oil runs of the test series were conducted using the mechanical atomizing oil burners normally used. At any load, a dirty stack occurred when the excess air was below 25 percent. Gas tests were made with existing burner rings. Oil and gas runs were made with loads and excess air levels corresponding to the methanol runs.

Methanol was tested at two excess air levels and at load levels of 100, 75, and 50 percent. Two blends containing higher alcohols were used successfully.

With the Y-type tips the appearance of the methanol flame was similar to a natural gas flame, except that the blue was not as bright. The rosette at the burner tip was clearly visible. Bright sparklers noted at the flame intersections disappeared quickly and did not float in the furnace. The furnace was clear at all times.

Soot deposits from oil firing were burned off by the methanol.

One methanol run was made to establish the excess air level at which CO would be excessive. At 11.1 percent excess air, the CO concentration was 750 parts/million. All other methanol runs were with CO concentrations less than 100 parts/million. Generally, the CO concentration for the methanol tests was less than that observed for the oil and gas tests.

No particulates were observed coming from the stack at any time. Figure 1 shows NO_x found in the flue gas was less than detected from natural gas and much less than from oil combustion. The figure presents emission data on M³ of NO_x lb/million Btu heat release versus unit load Mw. Spot analyses for aldehydes, organic acids, and hydrocarbon indicated that there were negligible quantities of these materials. Since there is no sulfur in methanol there were no SO₂ emissions.

The Manufacturing Chemist's Bulletin for methanol was studied by operating personnel. The methanol was handled just as other fuels.

The results of these tests showed that methanol may be used as a base fuel or supplemental fuel, depending on the overall economic and emission requirements of the system.

For boilers equipped with gas and oil burners, the oil burner modifications are relatively simple. In general, any type of liquid fuel burner may be adapted to use methanol.

If methanol is used as supplemental fuel, a dual supply system to the burners would be advantageous if rapid changeover is required, and essential if oil and methanol are to be fired simultaneously. Simultaneous use with oil in designated burners would average down the level of pollutants from oil firing.

Use of methanol as a turbine fuel also has considerable merit. Vulcan Cincinnati, Inc., has collaborated with the General Electric Company Gas Turbine Division in the successful demonstration of methanol combustion in a turbine combustor.

The principal results were:

1. All the physical combustion characteristics such as ignition, high and low flow blowout, temperature distribution, were within standard operating limits.
2. Measured NO_x emissions were quite low, being approximately 40 percent of the levels achieved on No. 2 distillate.
3. Preliminary estimates showed a possible 6 percent increase in output relative to a No. 2 distillate fueled machine. Subsequent work published by Mr. P. M. Jarvis of General Electric Turbine Division and by Mr. R. O. Klapatch of United Technologies leads to similar conclusions.

Methanol qualifies as a fuel for both intermediate and peaking load in turbines.

An important virtue of methyl fuel is the fact that it can be piped, shipped, transferred, and stored within the specifications now provided for a number of other liquid fuels. The storage tanks, piping systems, loading and off-loading equipment and tankers regularly used for petroleum can also be used for methanol.

It is significant that accidental spills of methanol in harbors or offshore would be of no serious consequences, and would present no fire or environmental hazards because of the rapid diffusion and complete miscibility and biodegradability of methanol in sea water.

I will spill some methyl fuel into water so you may observe the solubility after the panel discussion.

This makes it by far the most desirable source of energy to transport to meet both the energy and pollution problems affecting many areas of the world.

In regard to toxicity Andrew Moriarity, M.D., in his paper given on "Toxicological Aspects of Alcohol Fuel Utilization," presents the conclusion, and I quote, that "all available information to date indicates that the biomedical and environmental issues associated with the use of alcohol fuels are not critical...in fact the relative impact is clearly less than gasoline."

His paper was one given at the Second Annual International Symposium on Alcohol Fuel Technology held in Wolfsburg, Germany, in November 1977, sponsored in part by Volkswagen and the German Federal Ministry for Research & Technology. A compendium of all papers presented at that symposium is here in my possession and available for your review. Europe and Japan appear to be ahead of this country in giving proper attention to methanol as a fuel perhaps since it was used successfully in Europe during World War II.

As to the manufacture of methanol, commercial grade product is and has been manufactured here in California at Hercules, north of San Francisco, for many years, using Vulcan Cincinnati, Inc., technology.*

Methyl fuel produced from coal, or preferably the low grade lignite available in almost limitless quantities at relatively modest cost since its current uses are so limited, provides an ideal source of hydrocarbons for conversion to methanol.

* More recent private communication with the plant personnel in the Hercules California plant indicates that due to the high cost of purchased gas used as the raw material, the methanol, ammonia and urea plants have all been shut down and the overall plant closed. This makes even more tangible the need of coal energy and raw material sources for California.

With the Vulcan Cincinnati, Inc., process for methanol the only commercially proven American owned technology known to us, only the clean fuel would enter California from other States, to be used in boilers, turbines, automobiles and diesels. Impurities, ash, pollutants such as sulfur would remain at the mine-mouth plant for land reclamation and for sale of valuable by-products.

A new catalyst under development by Vulcan and presented in a paper at the Wolfsburg, Germany, seminar is designed to produce directly the blend of higher alcohols and methanol. We would see this as a significant breakthrough in methyl fuel technology.

To serve as the focus for a preliminary economic evaluation, Vulcan technology, from which seven methanol plants, including the largest plant, have been built, has developed a preliminary process design based on 5,000 ton modules to produce 25,000 short tons per day of methyl fuel from a plant at a lignite mine-mouth site making use of technology which has been reduced to commercial practice.

The total plant cost has been estimated to be about \$600 million in 1976 dollars. The methyl fuel selling price has been determined for each of three cases of lignite costing \$6, \$7 and \$8 per ton, and, on condition that all the utilities are supplied by the methyl fuel plant at no cost. Purchased oxygen is estimated at \$10 per ton.

It is anticipated that methanol product could be sold at about \$3 per million Btu's, depending on required return on investment and financing. Fuel grade methanol can be competitive at today's prices with alternative fuels as a source of energy even without credit for sales or utilization of any of the many by-products that exist.

I have several copies of an Executive Abstract on fuel grade methanol from lignite which you might want to review. A brief review of the executive summary of the recent Department of Energy "Conceptual Design of a Coal to Methanol Commercial Plant," leads to similar conclusion by our company of anticipated cost of methanol produced.

The block flow diagram, Figure 2, depicts the major process steps of methyl fuel production.

1. Lignite Preparation

Lignite is conveyed, stored, crushed and then ground to a fine particle size suitable for feed to the gasifier.

2. Lignite Gasification

The pulverized lignite is reacted with steam and oxygen at optimized temperature and pressure in the gasifier to produce a

crude synthesis gas. After heat recovery, the crude gas is quench-cooled and scrubbed free of ash and carbon particles.

3. Shift Conversion

The gasifier effluent gas is shifted to an appropriate H₂ to CO ratio in a shift converter. The gas from the converter flows in succession through heat exchangers.

4. Acid Gas Removal

Both hydrogen sulfide and carbon dioxide in the shift converter effluent are removed in this section.

5. Methyl Fuel Synthesis

Methyl fuel is produced by the catalytic reaction of carbon monoxide and hydrogen at optimized temperature and pressure in the reactor using specialized catalysts. The reactor effluent is cooled and methyl fuel product is condensed and separated.

6. Air Separation (by others)

The air separation process is the typical low pressure cycle process which is commercially available today.

7. Sulfur Recovery

Elementary sulfur is recovered from the acid-gas stream containing mainly carbon dioxide and hydrogen sulfide in this section.

Throughout the design concept of the plant, recognition of water shortages would be maintained. Cooling water usage would be minimized through closed cooling loops and through air-cooled heat exchanger. Low quality water would be utilized in the gasifier.

Mention has been made in earlier papers on the slurring of crushed coal in water and then pumping the mixture by pipeline to California.

A better solution may be to slurry coal in methanol produced at the mine-mouth, rather than in water.

The procedure would eliminate the need of pumping vast amounts of scarce water from the arid mine areas, would eliminate costly coal-water separation and drying at the point of usage, would produce an easier to burn fuel and would reduce SO₂, NO_x, and ash effluents from the boiler.

I would be pleased to discuss the subject further with you.

Thank you for your attention and interest.

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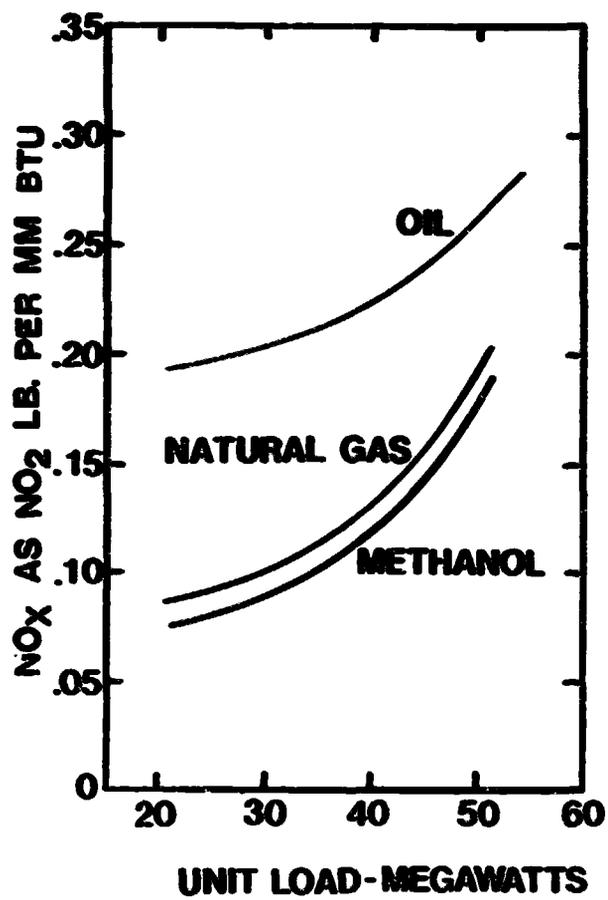


Figure 1

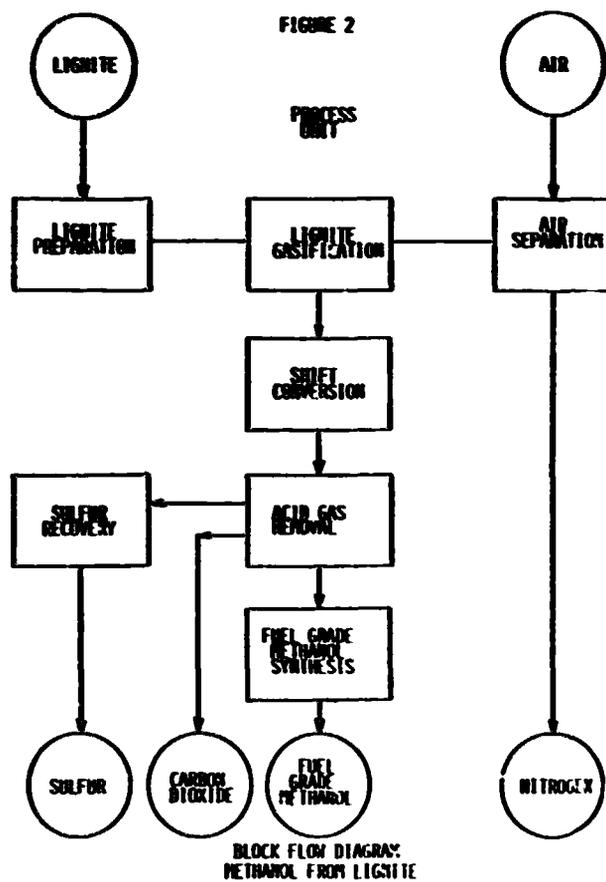


Figure 2

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SESSION IX: COAL TECHNOLOGY - LIQUEFACTION

Session Cochairmen: Roland Beck (DOE)
John Kalvinskas (JPL)

Speakers: Bob Hamilton (DOE)
George Chenoweth (Gulf Mineral Resources)
William Voss (Ashland Oil)
Larry Swabb (Exxon)
Don Miller (Vulcan Cincinnati Inc.)

OPEN DISCUSSION BY ATTENDEES

TEH FU YEN

I am from the Energy Resource and University of Southern California. The distinguished panelists really did their best to describe their own process, but I'm a little bit perplexed. In China we have a saying that, "Our own saying is the best but as far as wives, other people's are the best - and not my own." I hope you can bear this in mind for liquefaction of coal. What is the best for California, and remember now, it's not for any other state. I have a suggestion and I'd like to see what your reaction is.

LARRY SWABB

You asked several very difficult questions. I do not know of any liquefaction process to separate hydrogen rich and hydrogen-poor fractions of coal. Pyrolysis plus gasification is the closest to achieving the fuels you describe. In the last panel, one of the gasifiers described, was a two stage gasifier including pyrolysis and gasification. This type of process may have some commercial promise. I'd like to point out through that the pyrolysis liquid have much poorer quality than the liquid from direct hydroliquefaction in the processes described on this panel. This is because we are adding more hydrogen and obtaining a lighter product similar to a light crude oil. This difference in quality also means a difference in cost. It costs more to add hydrogen in a direct liquefaction process than it does to pyrolysis coal and collect the poor quality liquids overhead.

I can't really address the question of what's best for California. In the introduction Roland Beck mentioned that there are a few cars around that do need fuel. I really have not addressed, in my own mind, the question of actually locating a liquefaction plant in California. I'm not sure this is really necessary.

DONNA PIVIROTTO

I just had some short quickies. It looks like Mr. Voss has left. Did anyone know the units of his cost figures. He had capital cost of \$582 and \$896.

JOHN KALVINSKAS

I think they were per million BTU. They were capital costs, millions of dollars for million/BTUs.

DONNA PIVIROTTO

For Mr. Chenoweth, do you have any cost projections for your process? Also when do you believe that it will become commercial, what's your time frame?

GEORGE CHENOWETH

For the 6000 ton per day demonstration plant, we're estimating somewhere between 450 to 500 million dollars. The present schedule would be for that plant to be operational probably in early '83. It used to be mid '82, but now its early '83. The commercial 30,000 ton per day plant would probably be on the order of 1.5 to 2 billion in 1977 dollars. Again, we're projecting costs in the order of \$3.50 to \$4.00 per million BTUs in the commercial unit.

DONNA PIVIROTTO

Finally, on the donor solvent process, do you have any cost figures?

LARRY SWABB

Projected costs are often misleading. I would advise you not to depend too heavily upon what you hear or read, about what the projected

costs are going to be 5, 10 or 15 years from now.

Generally, indirect coal liquefaction oil processes are doing the same job technically, and the costs are going to be about the same. There is not a whole lot of difference. Actually in our cost studies we would estimate higher costs than any colleague here has quoted. However, costs are very dependent upon the basis used, such as the location, the coals, or what have you. I think it is best to consider that the costs are all about the same when doing the same liquefaction job.

RICK FLAGEN

On both the SRC process and the Exxon process, the numbers that were presented suggested that, at most, 1/4 to 1/3 of the organic nitrogen is removed from the fuel. This leaves a liquefied coal fuel which contains on the order of 1 percent or more nitrogen by weight, which is very high compared to currently used liquid fuels.

Do you have any comments on what's going to be required in the way of emission control for nitric oxide from burning these fuels.

LARRY SWABB

I can talk about that a little. You're right that the nitrogen is high; its on the order of about 1 percent in the 350° F+ fuel oil fraction. It can be reduced by hydrotreating the liquid product. This treating will produce products meeting present day standards, but future products are probably going to be another matter. I believe a tradeoff will be needed with regard to the degree of hydrotreating, the kind of combustion control used and the future standards. These tradeoffs will be needed in order to use the coal liquids. In some of our studies, we have achieved about 30% reduction of nitrogen in the fuel oil fraction by using conventional hydrotreating techniques.

MARK ZIERING:

I am from the California Energy Commission. These fuels are described as a low sulphur, but I'm wondering whether they are low enough to use them in California for power plant use without using scrubbers. Speaking specifically, for SRC process, we were quoted figures of .75% sulphur for SRC 1 and .25 for SRC 2. That is low for eastern coals, but not very low for western coals. I was wondering if there was any experience in treating western coals with the SRC process, and then how low the sulphur contents might be.

GEORGE CHENOWETH

No, up to this time we have only basically worked on the eastern coals. That's what the original process was developed for. Quite frankly, the process would require some modifications to successfully process the western coals.

MARK ZIERING:

Would these be very expensive modifications and not worth considering for California or would these be within some reasonable cost range.

GEORGE CHENOWETH

I think it would be reasonable but we would have to make some changes.

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RICHARD DIEHL

I am from the Aerojet Energy Conversion Company. Most of us who are working in the coal arena are familiar with the questions related to the report that was issued by DOE on methanol and prices.

Realizing that we have to put on a crystal ball at times, and really take guesstimates, can we get some guesstimates in 1985 dollars as to cost per million BTU of the synfuels, particularly the synoils versus methanol?

LARRY SWABB

I don't have a cost for liquefaction versus methanol. Again, I suggest being very careful about projecting costs. To make methanol from coal requires first gasifying the coal and then synthesizing the methanol. Our studies show that gasifying coal is the same, or at least, slightly lower in cost than liquefying coal. Therefore, the cost of methanol will be in the same order of magnitude as coal liquid.

RICHARD DIEHL

If I could make just one comment there. I was under the impression that there was a EPRI study done on gasifiers that indicated that there was significant difference cost based on gasifier used.

DON MILLER

I think that would probably be true. I'm not familiar with the report, but don't think there is any question that the higher pressure gasifier you use the more efficient the process would be, since methanol synthesis is carried out at elevated pressure.

I would volunteer that, we, as a criteria in looking for the ideal gasifier, would select one that, first of all, used oxygen rather than air and second of all, use one that is capable of higher pressure, and third, one which had a means of adding coal into the gasifier at high pressures. Clearly, we could add pure coal then, with some water, but we need some means of preparing a molten or liquid material which could be pumped. That is one of the reasons we were interested in the Jet Propulsion Laboratory coal pump; because it is a means of injecting the material, in a concentrated form, into a high pressure system. As far as the methanol versus the other liquefaction type processes is concerned, one of the differences is that there is no methanation step in methanol manufacture. That is very significant. As a shift conversion, it stays as a synthesis gas composition of CO and hydrogen during its period of reactivity in the reactor. We believe that's basically inherently less costly than going through some of the steps that we see on some of the liquefaction process.

BOB JULIAN

I am with the California Energy Commission. I have two questions that I'd like to ask from each of the panelists. One is, what would be the opportunity for cogeneration of electricity with these processes, and the second is what are the water requirements for the processes?

LARRY SWABB

I don't see much opportunity in cogeneration with the liquefaction process. I'm not sure what you had in mind. The type of process that we are designing is on the basis of a stand alone process, where it generates its own hydrogen, and its own fuel. So there is nothing left over, as far as fuel is required, for generating electricity.

BOB JULIAN

I'm referring to waste heat, is there any waste here that is recaptured?

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LARRY SWABB

We use everything possible, in order to maximize the efficiency of the process. We only reject low level heat, so there is really no high level heat available.

You asked about water. The design for a 60,000 barrel a day plant, which is the basis for our study design, uses about 5,000 gallons per minute to make up water, that's 8000 acre feet per year. We have done some studies to see what might be done to reduce that to the minimum. This goes down to about 3000, but that costs you in an investment and whether you would actually do this on a plant or not, depends upon the tradeoffs or the economics.

GEORGE CHENOWETH

At our planned SRC II demonstration plant site, we believe there is going to be limited supply of water available, and we are intending to build a plant, using substantial amounts of air cooling. We are planning to use around 6000 gallons per minute of makeup water for the 6000 tons a day unit and we are projecting more use of aerial coolers in the commercial plant and the usage there, would

be 20,000 gal p.m. As far as electrical generation, I think that there is all kinds of flexibility with any of these 3 processes, it all depends on where you can make the most money, which product you would make. You could even combine methanol production with some of the waste organic streams from either of the three processes.

DON MILLER

I would think our water requirements would be relatively similar. We would minimize its use through air cooled heat exchangers. We, of course, depending on the type of gasifier used, may have more than the stoichiometric amount of water in the gasification step that would inherently try to recover and reuse as much as possible. That water would not have to be high grade water. I want to stress that.

SESSION X

ECONOMICS OF COAL USE FOR CALIFORNIA

LIFE-CYCLE COSTS OF UTILIZING COAL IN CALIFORNIA

Charles E. Mann

Energy and Environmental Analysis, Inc.

Costs of coal delivered to utilities are discussed briefly, and reference is made to previous studies of the economics of coal vs. nuclear generation. Coal is seen to be within the realm of economic feasibility. Total capital and fuel

costs of using coal in industrial boilers in typical situations in California are compared. A discounted cash flow analysis of fuel and capital costs shows that coal may be economical compared to oil in new boilers in some cases.

NOTE: The complete paper was not available at the time of publication.

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INCENTIVES STRATEGY FOR INCREASING
COAL USE FOR CALIFORNIA

By
Russell Bardos
U.S. Department of Energy

Presented at the
Conference on Coal Use for California
May 9-11, 1978
Pasadena, California

INCENTIVES STRATEGY FOR INCREASING COAL
USE FOR CALIFORNIA

First, I would like to express my thanks to Mr. Nakamura for inviting me to participate in the conference. I must admit it takes little coaxing for me to talk on the subject of coal utilization. When the meeting place is in California, as well, no coaxing or additional incentives are necessary.

You have heard other speakers talk about the opportunities for coal use in California as an alternative energy source. You have also heard presentations on the status of the various coal technologies, as well as the environmental effects of these coal technologies. Thus, you are aware that there is a severe need for alternative energy sources, and that coal and coal technologies could have a potential role to play to help fill that need in California. It's quite apparent that industry and the utility companies have not been standing in line to install these coal-derived sources of energy. Why haven't coal and coal-derived fuels been utilized in California? If coal does have a role to play in helping California satisfy its future energy needs, what incentives can help bring this about? The question of what incentives strategy, if any, should be utilized is the subject I have been asked to discuss.

Figure 1 Outline of Presentation

To do this, I will first very briefly review the coal technologies which are, or which may be, available for use indicating their potential applications. I will briefly discuss the problems which exist for the use of coal-derived fuels in California. The incentives which could be utilized and the strategy for their use will then be discussed. I will conclude by indicating what Federal incentives now exist and are also pending before Congress.

Figure 2 Coal Technologies

It isn't a coincidence that the three coal technology sessions of this conference covered the three coal technologies listed on this figure. Direct burning, gasification and liquefaction are the three technologies associated with the use of coal as a fuel. Each of these technologies have potential market applications with specific economic, technical risk, environmental, socio-economic, and institutional factors associated with its use. In the case of high Btu (pipeline) gas or liquefaction major capital investments (over \$1 billion) are required for each plant with regulatory or legislative issues also involved.

Except for direct burning of coal and a few users of small low Btu gasifiers, there is essentially no other current commercial experience with these coal technologies in this country. There are processes which have been operating in other countries and processes under development which the Department of Energy is co-funding, but it will be several years before any one of these processes will be built and operating at a commercial scale.

So what is commercially available now, and at a relatively low technical risk?

Figure 3 Commercially Available Technologies

The technologies shown on the figure utilize commercially available processes which have been demonstrated and operated at a commercial scale. Although the Lurgi Gasifier is being used overseas, no commercial scale plant has been operated with all necessary components to produce high Btu gas as the end product.

A number of coal liquefaction and gasification processes are in the pilot plant/demonstration plant phase. None of these processes, however, can be considered to be commercially demonstrated and available today without some technical risk. Over the next several years, several of these processes such as SRC-II, synthetic and hygas may emerge as processes ready for commercial demonstration.

Given those technologies which are commercially available today, let's take a look at their potential applications.

Figure 4 Applications for Available Coal Technologies

In the industrial sector which consumes over 30 percent of the energy requirements of the state, natural gas is the primary fuel. In the electric utility sector natural gas, fuel oil, and hydro power are the primary sources of energy. In a state that uses 8 - 9 percent of the total energy used in the United States, it is surprising to find that only 2 - 3 percent of the state's energy requirements are now met with coal.

The California public utilities commission estimated that all priority 4 gas will be gone by 1980 and unless supplemental supplies can be found, even priority 3 users will be without service by 1985. This includes gas as a boiler fuel and for electrical generating facilities. Both AFB and coal gasification are technologies which could be used as alternative fuels for these applications.

What are the problems associated with using these commercially ready coal technologies?

Figure 5 Problems Faced by Coal Technologies in California

The problems listed on the figure are essentially the same problems that would be faced in the use of these technologies in any other state. The last two factors, however, are more significant in California than they would be in Kentucky or West Virginia.

The problems listed can be eased or eliminated by actions taken by the Federal and state government. These actions may be in the form of incentives, direct or indirect, by legislation such as enactment of an energy bill, or by establishing environmental standards that remove the uncertainty factor.

Figure 6 Incentive Analysis

In the case of new technologies there are different incentives which may be used depending on the objective one is trying to achieve. With any new technology, the initial desired effect of an incentive is the reduction of the risk factor. This can be done by the sponsoring of, or cost sharing in, early commercial demonstrations. In so doing (T_0) or start of commercialization of the new technology can be moved up in time.

The rate of market penetration of the new technology, as determined by the level of return in relation to the risk involved can be influenced by various forms of cost sharing, failure guarantees, price supports, etc, thereby accelerating the rate of penetration of the technology in the market.

Finally, the extent of market penetration will be determined by a number of factors. Its social acceptance as well as the cost of the fuel versus other available fuels are of primary importance. Both of these factors can be affected by price subsidies and/or regulation.

Figure 6 Representative Forms of Federal Application Support

A summary list of the Federal (and state) incentives or supports which are most frequently discussed are listed on the figure. As indicated some are directed toward reduction of risk while others can potentially augment return on investment or improve the competitiveness of the technology. The incentives strategy used would depend on the status of the technology, the economics as related to other available fuels and the social acceptability of the technology.

All of these incentives whether Federal or state funded must be justified by demonstrated public benefits. The private benefits are measured in terms of return on investment. Public benefits are measured in terms of the accomplishment of social goals. The associated public costs appear in the form of direct budget outlays or tax deferrals.

At the present time there are limited Federal incentives available to support the acceleration or stimulation of the use of new coal technologies. The Department of Energy is cost sharing in the design, construction, and operation of several coal technology commercial demonstration projects at this time. At least eleven gasification projects (high, medium, and low) are in some phase of design, construction or operation. Not all of these plants will be built. Limited funding and selection based on technical criteria will limit the HBC and HGC to possibly one plant each. Five atmospheric fluidized bed and 5 coal/oil mixture commercial demonstration cost shared projects are also in design, construction, or operation at this time. All of these commercial demonstration projects are Federal incentives directed toward reducing the risk of the new technology.

The Department of Energy has authority for capital grants, however, limited funds restrict the use of this incentive. Public Law 95-238, the Department of Energy Authorization Bill, contained a provision for loan guarantee authority for alternative fuels, such as, gasification, liquefaction, biomass, and oil shale projects. No borrowing authority or appropriations are available at this time and it will take at least 12 - 18 months to establish regulations, obtain the necessary appropriations, and establish a loan guarantee program.

As for what incentives are pending in Congress as part of the Energy Bill, all I can say is that there are specific tax credits, depletion allowances, industrial revenue bonds, and user taxes in both the House and Senate Bills. Your guess is as good as mine as to what will finally evolve as an Energy Bill. What incentives finally evolve with or without gas deregulation will be a significant influence on what actions will be taken by industry and states in switching to alternative energy sources.

I have attempted to give you an overview of the commercially available coal technologies and the problems associated with using each. The incentives strategy for overcoming these problems can be rationalized. Bringing about and initiating the necessary incentives is a major problem at both the Federal and state level for all of these incentives translate to dollars. If the energy problem is a serious matter in California, or nationally, then the cost of the necessary incentives is justified and should be of the highest priority.

If you have any questions, I will do my best to answer them.

Thank you for your attention.

* * * *

REPRODUCIBILITY OF THE ORIGINAL PAGE IS POOR

- COAL TECHNOLOGIES
 - STATUS
 - APPLICATIONS
- PROBLEMS IN UTILIZING TECHNOLOGIES
- INCENTIVES/STRATEGY
- EXISTING AND PENDING INCENTIVES

Figure 1. Outline of presentation

- DIRECT BURNING
 - WITH SCRUBBERS
 - FLUIDIZED BED
 - COAL/OIL MIXTURE
- GASIFICATION
 - LOW BTU
 - MEDIUM BTU
 - HIGH BTU
- LIQUEFACTION
 - SRC II
 - METHANOL

Figure 2. Coal technologies

- ATMOSPHERIC FLUIDIZED BED COMBUSTION (AFB)
- COAL/OIL MIXTURE (COM)
- LOW AND MEDIUM BTU GASIFICATION (LBG AND MBG)
- HIGH BTU GASIFICATION (LURGI) (HBG)

Figure 3. Commercially available technologies

	<u>BOILERS</u>		<u>INDUSTRIAL FUEL GAS</u>		
	<u>PROCESS STEAM</u>	<u>ELECTRICITY GENERATION</u>	<u>SMALL USERS ON-SITE</u>	<u>LARGE USERS WITH DISTRIBUTION</u>	<u>PIPELINE GAS</u>
AFB	X	X			
COM	X	X			
LBG	X	X	X		
MBG	X	X		X	
HBG					X

Figure 4. Applications for available coal technologies

- RISK IN BEING FIRST
- UNCERTAINTY OF RETURN ON INVESTMENT
 - HIGH CAPITAL COST
 - NOT COMPETITIVE
- UNCERTAIN NATIONAL POLICIES
- ENVIRONMENTAL CONSTRAINTS/UNCERTAINTIES
- NO INDIGENOUS COAL SUPPLY

Figure 5. Problems faced by coal technologies in California

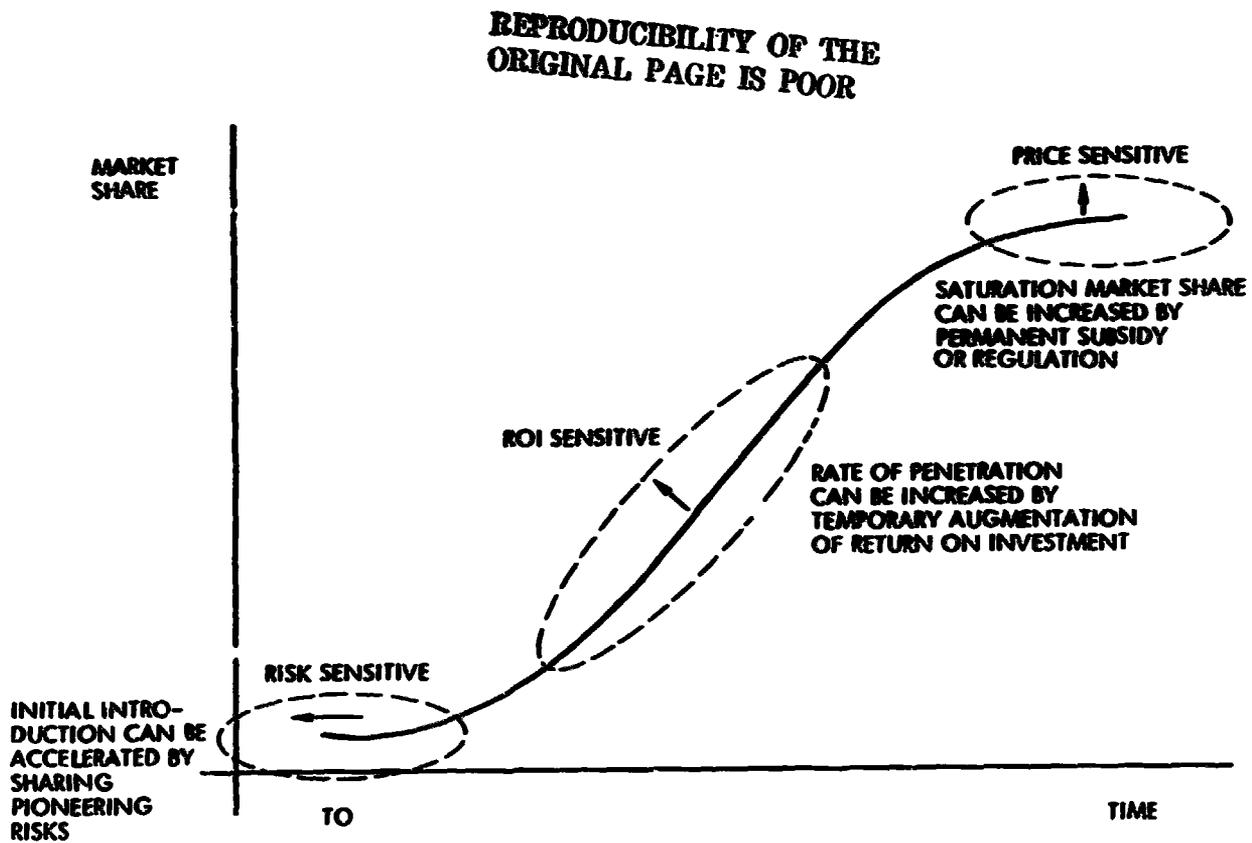


Figure 6. Incentive analysis (what do we want to do?)

FINANCING CAPITAL REQUIREMENTS FOR COAL FOR CALIFORNIA

Edward L. Vickers
Vice President

Bank of America
San Francisco, California

ABSTRACT

The development of future mining new ventures is increasingly dependent on considerations other than purely technical mining engineering evaluations. The ability to begin a mine has become heavily dependent on the ability to raise financing which, in turn, has a significant impact on the structure of the venture itself. The mining engineer and the banker have now become partners in the planning and development of new mines to a degree which has taken both unawares.

The theme of the conference here today is "Coal Use for California." I have been asked to discuss the financing of capital requirements for the required coal developments. Attracting required financing is clearly a very key element. Claims on cash flow for debt service have risen to the point that they are equal to or often greater than all other costs of new resource developments. Clearly then financing considerations become an integral part in the planning of a new venture. This planning for financing must begin at an early stage, such that its ramifications can be factored into the design of any new venture.

You might ask why have financing considerations become so important? I think we might begin this discussion by reviewing some of the changes that have caused this development.

One thing is certain--no one force has had to do more with our present predicament than inflation. Because normal and real growth must be financed, persistent inflation has resulted in substantial unproductive debt burden. Inflation has contributed significantly to a rapid deterioration of the credit-worthiness of many industrial sectors. A prime example being the public basic industries. Mining companies surely face this problem. This industry supported itself largely through internally generated funds and, as late as 1960, was virtually debt-free. By 1970 the debt ratio had increased to slightly over 20% and by 1976 was in excess of 30%. There is general agreement in industry circles as well as the financial community that this number is fast approaching prudent limits.

Another significant change that the developers of resources must live with is that of greater governmental regulations. These impact significant elements of the project's economics finding their influence in price controls, permitting, and royalty payments. Closely allied to this type are environmental considerations. Such regulations may indeed be beneficial to our country as a whole and need not always be resisted by the project developers. What is to be feared, however, are the uncertainties that go with these regulations. The constantly changing standards and guidelines make both the banker and the developer exceedingly

nervous as he cannot, with any reasonable degree of certainty, know the requirements he must satisfy.

While capital and operating costs have been pushed ever upward, profits have tended to remain relatively flat or, in many instances, decreased. Although there was a rapid increase in the price of coal shortly after the increase in OPEC oil prices, these margins of increase have been eroded away by increased costs. These factors again have eroded the borrowing capabilities of many companies.

Many of the resource developments today are not simply single owner developments, but are rather done as complex consortiums. These are created for a multitude of reasons. One of the most obvious is, of course, sharing the risk. Another is the inclusion, within the ownership group, of the purchasers of the output. These complex ownership structures significantly impact the way a venture can be put together and the mechanisms by which the needed funds are mobilized.

To cope with this increasingly complex environment, greater emphasis has been placed on the financing of major energy ventures as a stand alone project rather than the balance sheets of the sponsors. This has led to the development of financing techniques generally referred to as project financing. This activity is identified by many definitions but generally can be thought of, basically, as cash flow financing where lenders look to the future earnings for a specific venture as a source of repayment. These financings are supported directly and indirectly through an often complex network of agreements. The basic objective in terms of credit support is to allocate responsibility as broadly as possible to those entities receiving the benefit from the venture. Balance sheets are not to be ignored in this type of financing as the underlying strength of the companies assuming various supports remain strong.

This perhaps does offer some partial solution but is no panacea to cope with many of the problems of coal development. Banks are lenders and not participants in the equity rewards of a venture and, as such, they cannot be placed in a position of assuming the downside risk that must also be associated with equity ownership.

I think perhaps it would be worthwhile here to focus on how bankers evaluate the financing of a coal project. This process will comprise essentially two steps. The first is to be convinced that the venture, irrespective of financial considerations, is in fact viable and, secondly, given such a situation exists, structuring a financing package which will appropriately distribute the credit supports needed to produce a true lending situation while, at the same time, accommodating the objectives of the sponsors.

Let us begin with the first of these two steps which is an exercise in identifying, evaluating and quantifying the uncertainties associated with a new venture.

These uncertainties will fall into two broad categories, basically the technological uncertainties and the political uncertainties. Normally there will be an element of both to a greater or lesser degree in each broad category of risk evaluation.

In addressing the risk, lenders seek protection in various ways and sponsors seek to limit their credit responsibility. Evaluation of risk factors by owners and lenders is time-consuming, especially in an environment of inflation, commodity price fluctuations and changing political forces. Many projects are in the formative stage for two to three years plus a construction period of often four years. Changes during these periods must be expected and coped with.

To briefly enumerate some of the risks, one need only look to the significant variables in a resource project. They would include:

- Ore Reserves
- Capital Cost Estimates
- Operating Cost Estimates
- Labor Appraisals
- Markets

This is by no means complete but is the kind of thing the banker will be evaluating and, as I have said, he will be evaluating these from both the technological point of view and the political factors that impact these considerations.

Despite all of the future uncertainties, however, ventures do emerge from the scrutiny as intrinsically attractive and thus we can move to the second phase of the financial considerations--namely the structuring of a financially solid credit and securing the necessary funds for the venture.

Let us now briefly examine the capital markets. Most resource developments are heavily dependent on the commercial banks for their funding. The situation of bankers is not altogether enviable. During periods of economic boom and tight liquidity the demand for bank funds is generally enormous and lending institutions can selectively choose those less risky ventures. During periods of abundant liquidity in the banking system, which have most often corresponded to recessionary or lackluster economic activities, price forecasting for products is much more difficult. This generally reduces the lenders' perception of the viability of many projects. Credit standards, whether self-directed or externally imposed by the banking regulatory agencies, preclude, and in my judgment rightfully so, lenders taking unusually high risks. It is thoroughly imprudent for loan funds to assume an equity risk at bankers' spreads. Excessively highly leveraged ventures and limited support by the project sponsors can clearly be classified as high risk lending.

Another consideration associated with funding is the term of the loan. Banks, unfortunately, do not usually have the capacity to lend with tenors in excess of seven to eight years due to the relative short-term nature of their deposits. Projects

requiring three to four-year construction periods are the rule rather than the exception today. It becomes quite cumbersome and even impractical for a venture to amortize its debt obligations in such few remaining years of the loan.

As a source of funds other than banks, one has to be realistic. The U.S. institutional funds require top credit ratings which are often much more restrictive than commercial banks. When available, these are highly desirable sources as their tenor is generally considerably longer than that of commercial banks.

Substantial funds may often be secured at times from users or buyers of the product. A prime example of this is a mine-mouth utility station. These long term sales contracts are further advantageous in that they may constitute an integral part of future credit support.

After all these sources of borrowed funds have been exhausted, the remaining cost of the project will be borne by equity or quasi-equity instruments. The magnitude of equity will be discussed in more detail later, but it is sufficient to say at this point that lenders will always evaluate the seriousness of the project's sponsors from the point of view of this equity input. It is recognized today by the banking industry that equity in the form of common stock is not always either available or desirable. By using the vehicle of subordinated debt, effective equity can be substantially increased in a project. Such an arrangement might be acceptable to senior lenders if there is a true agreement of subordination with respect to both principal and amortization.

Well, I have now burdened you sufficiently with many of the problems facing the development of new coal resources. Let us try to be a little more creative and suggest some of the ways in which they can be made workable. Despite these many difficulties in the capital market, there is no question that ventures with attractive economics and properly structured have a good chance of being financed to the satisfaction of their sponsors. What are then the necessary credit prerequisites to secure financing for a venture?

In the following discussion I will attempt to discuss some of the individual credit support mechanisms with the caution that they can never be considered in a vacuum; instead they must always be viewed in terms of an explicitly defined overall credit package. Let us address the subject of how much equity is necessary--generally the first question asked by a potential borrower. The degree of leverage the project can withstand depends basically on two factors. Firstly, the ability of the project to meet its scheduled debt repayments and, secondly, to maintain a level of credit strength in terms of the sponsors' clear dedication to the venture. Assuming constant cash flow from a potential venture, an increase in the level of debt and a reduction in equity funds clearly results in a higher credit risk.

The amount of equity is of critical importance from the sponsors' point of view in that it not only severely impacts the amount of money needed to get the venture off the ground, but their yield on investments as well. The factors I have just discussed all significantly impact this determination.

There are a few other quantitative criteria, however that are useful in getting a handle on this elusive number. Bankers in project financing very carefully look at a yardstick that they define as the debt coverage ratio. This, simply stated, is the capacity of the venture to service its debt. It is determined by an equation which consists of net income plus depreciation plus interest expense minus capital expenditures divided by the annual principal and interest obligations. Clearly a one to one ratio is unacceptable as it permits no margin of error in estimating which, by definition, is uncertain. However, given the same cash flow the ratio can be increased to an acceptable level by the simple expedient of reducing the amount of debt to be serviced. As a yardstick of an initial project evaluation this ratio should be in a range of 1.5:1. In other words, a 50% cushion. This having been said, however, the amount of equity is subject to many considerations. Support of ventures when their own cash flow is deemed to be too uncertain can often be accomplished by various contractual obligations or guarantees. These supports can often shift the responsibility for uncertainties and, as a consequence, reduce the required equity by lenders. The 1.5:1 ratio imposes a very severe burden on many projects today. The basic reason is one we cited earlier--namely the long construction period has used up a significant percentage of the loan tenor and the debt servicing obligations are compressed into such a short time frame that in many instances only very lucrative ventures can meet this yardstick. We are largely looking to the future when we talk about cash flow financing. The creation of a production facility capable of a defined output which, in turn, is sold on long-term contracts linked by various agreements are all necessary to establish this cash flow.

The nature of the facility is important in the determination of its ability to produce a viable product. Normally, in the financing of a resource project, a feasibility study has been prepared which contemplates a production facility with certain specific operating characteristics. The financing community must be assured that such a facility is in fact created and operates within designed expectations. To assure this the banks normally insist on some form of a performance and completion agreement. The parties to the venture must provide these assurances. In this context they must, in some manner, cope with the uncertainties of cost overruns either by agreeing to provide any unanticipated capital requirements and/or through overrun back-up financing. This type of undertaking by the sponsors clearly results in a significant financial burden during construction periods. It, however, does permit the sponsors to extend their credit as well as capacities to develop other ventures as such credit supports drop away upon satisfying these conditions.

On the other side of the equation we come to the marketing of the product. We have assured ourselves that a product will be produced and now we must be assured of the cash flow from the sale of this product through long-term sales agreements.

The sales contracts will bring to the venture additional principals who expect to receive benefit by way of assured long-term supplies. These benefits can be traded for additional credit support to the venture. Sales contracts have become one of the most lucrative areas on which new projects can

be made sufficiently credit-worthy to move forward. Sales contracts come in a myriad of forms and rank from the extremely strong "hell or high water" take or pay to less credit-worthy but yet very useful take and pay agreements. Take or pay agreements are often used in pipeline construction or jointly owned tolling companies where the contractor guarantees to at least a cash flow adequate to meet debt servicing even though production flow is interrupted. Sales contracts with a floor price adequate to meet debt coverages are extremely valuable even though they may have interruptible provisions. Careful structuring can often cope with these interruptions in such a way as to continue the credit-worthiness of the project and yet not have this full obligation placed on any individual party involved in the project. Sales contracts are such an intricate part of project financing that it is extremely valuable, in the early conceptual stages of a venture, to develop a dialogue with the financing agencies ensuring that maximum benefit is conveyed to the venture.

The production facility and the sales contract can be further linked through secondary direct and indirect support considerations. These can take the form of working capital maintenance agreements, deficiency agreements, raw material supply agreements, etc. Each attempts to provide additional support to a venture while, at the same time, not unduly burdening the sponsors with the full credit support of the venture.

This leads me to one other significant consideration that is especially germane to a group such as this. In an ideal world, optimization of design and scale is clearly to be sought. Unfortunately, this ideal world is constrained by practicalities, not the least of which is the financial market. The projects today are fraught with huge capital requirements growing at such a rate that the absolute magnitude can well exceed the financial community's capacity to cope. It is not uncommon today to hear of \$2, \$3 and even \$4 billion dollar projects. By any standards this is a lot of money. Such financings strain the very fabric of the countries' financing organizations. They are so monstrous that by and large many become unattainable. Time and time again we see desirable and well conceived ventures having a capital cost so high as to preclude their being done. Delay upon delay ensues until it dies of its own weight. Clearly engineers and planners involved in the design and scoping of new ventures, should reckon with this simple fact. It does not matter how good or economic the venture is, if it cannot be made to fly it is nonetheless useless.

I have reviewed with you the broad outlines of resource financing. Now let us briefly focus on some general categories of project developments and how specific financing techniques may apply. The first of these, for lack of a better name, we can call "take out financing." In this instance we are largely dealing with a completed facility that has a demonstrated cash flow and thus should provide the basis for borrowing. Perhaps the most common form of this is production payment financing. This has its roots in energy financing dating back to the 1930's with the financing of many independent oil wildcatters. It has spread in its application to coal mine financing on a broad scale. Today it is one of the most popular forms of financing employed in the energy section.

The second general category of financing relates to the expansion of existing facilities. This class of financing, although less certain than the first, does have a demonstrated track record of operations on which to rely. An increasingly popular technique is the creation of the joint venture company for the purpose of holding existing facilities appraised at market value and thus providing a degree of financial underpinning. It also provides a very broad range of imaginative financing opportunities. The advantages here can be the taking over of existing assets, a cash flow record, technical know-how and a demonstrated track record.

The final category is the green field project. This is certainly the most difficult requiring the greatest degree of parental support. Properly supported and adequately evaluated, these too can be made to go forward, without unduly burdening any individual participant as large elements of the credit supports are drawn from the venture.

The primary thrust of my comments here today relates to providing financing of resources and energy projects, largely on the basis of expected cash flow. The capital requirements of these industries are clearly extremely large but we do feel that capital will be available to meet these demands given an environment with a reasonable degree of certainty. I have not addressed myself to the

objectives of an individual company, objectives that may be directed at achieving off-balance sheet treatment, limited recourse or coping with indenture restraints. These are clearly worthwhile objectives of any sponsor. I feel that more and more the commercial banking industry is capable of aiding in achieving these. Project Financing is a very lucrative area for such endeavor. Yet, however, as I stated before, it is no vehicle by which an otherwise unattractive venture can be made to fly. The banking industry is a lender and not an investor and thus must have a solid credit against which to extend funds. I believe we can be responsive to the requirements of industry and aid in ensuring the required flow of capital while, at the same time, satisfying the objectives of individual sponsors.

I have broadly outlined here for you today some of the problems and, hopefully, some avenues of solution. The financial community and the developers of energy projects are more and more drawn into a working partnership. Each must be flexible and imaginative. The problems we are discussing here today are not those solely of any one factor, but involve us all. Cooperation and dialogue at every stage are imperative. Also, it is imperative that those with the capacity to influence the political arena in which these developments must take place be aware of the impact their decisions have on the resources and energy developments of the future.

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FUEL ADJUSTMENT CLAUSES FOR CALIFORNIA

Nowell E. Rush

Washington Utility Group, Ernst & Ernst
Washington, D. C.

As California utilities begin to utilize coal for generation of electricity, there are three important issues that must be addressed by the regulatory commission, the utilities, and the California ratepayers. These issues are:

- (1) How are the coal costs to be recovered?
- (2) What can a utility do to monitor and control coal costs and how can it demonstrate that it is procuring coal at the minimum price?
- (3) What can the regulators do to monitor the procurement and fuel cost areas?

My talk this afternoon discusses the importance of these issues and provides a program to address each one.

HOW ARE THE COAL COSTS TO BE RECOVERED?

The first issue, "How are the coal costs to be recovered", is a particularly important one because the cost of fuel for a utility is extremely large in proportion to other individual utility expenses and because the cost level of fuel, especially coal, to a given utility may change frequently and significantly. These cost changes, (both up and down) which generally arise from forces outside the control of utility management, may be more pronounced for coal than oil or gas since coal prices are still set in a competitive market. Consequently, absent hearings or some other mechanism to adjust for coal cost changes, substantial mismatching of fuel cost, and fuel revenue can arise for both consumers and the utilities. Options for handling this problem range from monthly hearings (the work for which seems to exceed the benefit), through quarterly, semi-annual, or annual hearings (which allow for growing mismatches), through treatment in rate hearings only, to a fuel adjustment clause with controls. I believe that fuel costs warrant special consideration in the ratemaking process and that fuel or energy adjustment clauses, properly constructed, administered, monitored, and communicated, provide a reasonable answer to the question, "How are the coal costs to be recovered?"

To simply have a fuel adjustment clause in place, however, is not enough. The clause must specifically be designed to account for the idiosyncracies of coal procurement. Having designed, implemented, and worked with fuel adjustment clauses in states that are users of coal in addition to other fuel sources, we have found that there are several elements that compose a good clause for coal. Basically we have found that the fuel adjustment clause must meet the following three objectives:

- (1) It must insure that only energy costs are charged to the customer.
- (2) It must provide the ability to obtain revenue concurrent with costs.
- (3) It must distribute costs equitably among customer classes on the basis of services rendered.

To meet these objectives we believe that a good fuel adjustment clause, or energy cost adjustment clause as we prefer to call it, have the following characteristics:

- (1) The billing adjustment surcharge should be computed directly as ¢/KWH as opposed to ¢/MBTU--this is easier for the consumer to understand and directly reflects the effect of line losses and the efficiency of the boiler/turbine in converting coal to electrical energy.
- (2) The billing adjustment surcharge (BAS) to recover the energy cost is calculated by:

$$\text{BAS} = \frac{\text{Average Monthly Energy Cost}}{\text{Average Monthly KWH Sales}}$$

The cost component of this adjustment includes both the acquisition cost and transportation cost of procuring coal, but excludes handling cost at the station since this expense is directly under the control of management. More simply, it is those fuel costs inventoried in FPC account code 151 and cleared to FPC account code 501.

- (3) The cost and KWH values used in the computation of the BAS should be averages based on the actual fuel cost and KWH sales for the last month and the forecasted fuel cost and KWH sales for the current and upcoming month.

In this way, if fuel costs are falling or rising, the utility has the ability to anticipate these changes and estimate a BAS that can more clearly approximate what is actually happening in the current month. Further, since there is likely to be some predictable seasonal swings in the KWH sold, it is possible to better approximate current sales. We believe that this methodology is an improvement over using historical averages which delay collection, provide costs which are different from current costs, and which are based on KWH sales that are likely to differ from the current actual KWH sold.

- (4) The fuel clause should be based on the total cost of fuel and purchased power. The cost of purchased power is defined as the fuel and demand charges if this cost is less than the utility's incremental fuel cost and as only the fuel cost portion if the purchased power is more expensive than the incremental fuel cost. The cost of fuel used in sales for resale should be deducted from the total cost since usually higher cost fuel is used to supply these consumers, and the utility's ultimate customers should benefit from these sales.
- (5) In a like manner, the fuel clause should be based on total KWH sold less the KWH associated with sales for resale.
- (6) The billing adjustment surcharge so determined should then be applied to all residential, commercial, and industrial customers alike. The computation of the BAS is based upon total retail sales, and it contemplates an equal proration of costs to all customers based on KWH used. Since energy costs are directly variable with KWH produced, it seems appropriate to charge all KWH equally.
- (7) The clause should contain a reconciliation adjustment to correct for differences between estimated costs and sales and actual costs and sales--this reconciliation will allow the consumer to bear only the actual fuel costs incurred.

There are many benefits that result from an energy cost adjustment clause of this type including the facts that:

- (1) It is easy to understand by the ratepayer, the utility and the Commission.
- (2) It matches energy costs and offsetting revenues on a current basis.
- (3) It prevents a cumulative over- or under-recovery situation.

Since California has the luxury of time in preparing for the use of coal in its power plants, I strongly urge the Commission and the utilities to get together now to develop a good, workable clause that addresses these aspects I have brought up today so that you will be fully prepared for the time when coal is used extensively in California.

WHAT CAN A UTILITY DO TO MONITOR AND CONTROL COSTS?

The second issue I will address today is "What can a utility do to control and monitor coal and how can they demonstrate that they have attempted to minimize fuel costs?" With the use of an FAC, utilities are often opened to the charge that they have no incentive to procure at the least cost since they can simply pass the fuel costs straight through to the ratepayer. Today I will briefly lay out the procurement activities necessary for a utility to assure itself that it is procuring fuel at the best price and, (this is important) if the utility will properly document these activities, can assure the ratepayers and regulatory agencies of this fact also.

These five important procurement activities are:

- (1) Planning (both short and long-range).
- (2) Source and vendor selection.
- (3) Contract negotiation.
- (4) Contract monitoring and enforcement.
- (5) Transportation control.

Each of these activities will be addressed separately.

Planning

Planning by the utility must include both short- and long-range planning to insure that adequate, reliable supplies of fuel are available for existing and new plants. The fuel planning efforts must closely, if not inextricably, be tied to the utility's operational and capacity planning efforts, and must consider extraordinary events particular to coal such as labor strikes, spot-market trends, desired inventory levels and so forth. At a minimum, the planning procedures must insure that adequate coal shipments are received at the plant on a short-range basis and that adequate supplies are lined up on a long-range basis.

Source and Vendor Selection

Source and vendor selection involves the utility's decision on whether it should own its own supplies or use contract vendors. Further, if vendors are used, it involves the utilities practices to identify and select supplies. This area is very important since this is the actual determination regarding from where the coal will come.

In source selection, the utility has a responsibility to justify, on an economic basis, its

choice between owning its own supplies and procuring coal from a supplier. Consequently, the utility must document its deliberations between captive and noncaptive sources, including a comparison of cost expectations between the sources over the life of the mine or contract. In vendor selection, the utility must be able to demonstrate that it has adequately surveyed the coal market and has selected the vendor(s) that provide the "best" price where the best price is defined as the least priced coal that is of an adequate quality from a reliable and secure source. Generally, this requires that the utility utilize a competitive bidding process combined with an evaluated best buy analysis. The evaluated best buy must consider such aspects as coal quality, transportation costs, expected escalation or cost increases, and reliability of the supplier.

Contract Negotiation

Contract negotiation is the next important area of coal procurement. Here the utility is generally best served if it uses the team approach to negotiation, with the team composed of procurement, operations, financial, and legal personnel. The company should keep good records of its negotiation strategy, especially with respect to significant contract decisions. For example, the basic decision regarding base price plus escalation contracts versus cost plus profit contracts should be documented in a manner similar to the captive versus noncaptive mine decision. It has been our experience that either type contract may be the most appropriate for a given situation, but that after the fact justification of a cost plus contract can be very difficult if it does not contain a good productivity incentive clause and is not backed up with good economic analyses.

At a minimum, whatever contract a utility settles on, it must explicitly define the allowable quality of the coal and the penalties for substandard quality, the required quantities and penalties for failure to meet required quantities, the method of transportation and corresponding responsibilities for it, and the price and the allowable escalations or increases in price.

Contract Monitoring and Enforcement

Monitoring and enforcement of contract terms is the seemingly simple, but all important activity of ensuring that the supplier lives up to the terms of his contract. Basically the utility must:

- (1) Review all price escalation requests and fully document actions taken with respect to these requests.
- (2) Pursue reasons for all quantity short falls, and record actions taken with respect to the short falls.
- (3) Develop a system for monitoring the quality (BTU, sulfur, ash, moisture, grindability, etc.) of coal received under all contracts, and documenting the action taken with respect to receipt of low-quality coal.

Transportation

The last major area of fuel procurement is transportation. Since the delivered price of coal is the true test of a best buy, transportation costs must be a basic part of every procurement

decision. Actually, transportation decisions demand the same attention that procurement decisions receive in that they must receive aggressive planning, vendor selection, contract negotiation and contract monitoring efforts and be backed up by a good documentation system.

If a utility will fully address each of these five areas and document its actions in each, it can minimize coal cost and can assure itself, its ratepayers and its regulatory agencies of this fact.

WHAT CAN REGULATORS DO TO MONITOR THE COAL PROCUREMENT AND FUEL COST AREAS?

The third area I will discuss today involves the question "What can regulators do to monitor the coal procurement and fuel cost areas?" The simple answer to this question is that the regulators must monitor the fuel clause and procurement operations of the utilities. This monitoring should be of two kinds: One to check on a monthly basis that the utility is computing the fuel adjustment correctly and is applying it to customer bills on a current basis. The second is to perform a major periodic review of the utility's efforts to secure fuel at the least price and to carefully examine the conformance of the actual BAS to the written clause. Since we allow unit efficiency and line losses to flow through the clause, this audit should also monitor maintenance of each unit's efficiency and system losses.

It is our experience that the regulatory entities controlling the use of an FAC have followed divergent paths in the use of monthly review. At one extreme, some entities require only that the utility file their cost and computation sheets at the time of the monthly adjustment. These filings may or may not receive a detailed review by the staff of the regulatory entity. At the other extreme, some entities have simply abolished energy adjustment clauses completely and leave it to the utility to file full rate cases whenever they feel they need relief. In between, there are entities who (1) permit monthly flow through, but require full fuel clause audits each year; (2) require a monthly hearing prior to implementation of a BAS charge; (3) allow collection of BAS amounts subject to refund until the monthly hearing is held; and (4) several other variations.

If the regulatory agency feels the need to monitor monthly, we suggest that the utility be required to submit the cost and computation material, plus the percent change from the last month and the changes in operation mix and fuel price that drive the percent change. The new BAS would go into effect subject to refund until cleared by the regulatory agency. This approach insures that each change will be looked at, the utility can recover costs in a timely fashion, and the ratepayers are protected against any mistakes.

The second or major audit effort should be composed of two audits per year with one going into extensive detail concerning fuel procurement and conformance of all FAC collections in the previous twelve months with the terms and

conditions of the clause. The second or semi-annual audit, performed six months after the major audit, would focus on any questions or issues that came up in the prior six months. If things ran smoothly, it may well be possible to make this a relatively small review.

The major annual audit program would consist of two major work programs: (1) a conformance review designed to test the degree to which the utility is operating in compliance with the terms and conditions of its FAC; and (2) a procurement/operations review designed to see if the utility is securing fuel at the "best" price and purchased power most economically.

These two types of reviews should provide ample information to the regulators to insure that fuel adjustments are in conformance with the fuel clause and that coal is being procured at the "best" price.

SUMMARY

In summary, I would like to say that California is blessed with an unusual advantage in that it has the opportunity to adequately prepare for a smooth transition into the use of coal for generation of electricity and can benefit from the successes and failures of other commissions and utilities. I therefore, strongly urge that the State do several things--first the Commission should implement a good fuel adjustment clause structured specifically to handle coal, second the utilities should prepare good coal procurement procedures that fully address the five areas I discussed earlier and ensure that the procurement actions are adequately documented and, lastly, the Commission should implement a good monitoring program through which the consumers and the Commission can be assured that good procurement decisions are being made. If the State will work together to do these things and if they'll begin now, then California will be able to fully benefit from the use of coal to generate electricity in California.

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SESSION X: ECONOMICS OF COAL USE FOR CALIFORNIA

Session Cochairmen: Louis Meyer (Drexel, Burnham, and Lambert)
Richard O'Toole (JPL)

Speakers: Charles Mann (Energy and Environmental
Analysis, Inc.)
Russell Bardoos (DOE)
Edward Vickers (Bank of America)
Noel Rush (Ernst & Ernst)

OPEN DISCUSSION BY ATTENDEES

JOHN GEESMAN

I am with the California Citizen Action Group. I've got a question for Mr. Vickers. Is it your feeling that most of the utility use of coal in California will require some form of project financing?

EDWARD VICKERS

I would think probably so, particularly in the research development. The cost of a mine today 's so high that, I think the organizations that would normally be the ones expected to put this in would be either existing mining companies or consortium or utilities or what have you. I believe that the main thrust is going to be to have that utilized to the extent possible to purchase contracts from the utility and project financing to keep it as much off the books of the sponsoring companies as possible, and spread the risk.

JOHN GEESMAN

One last question, what, in a more specific sense, are we talking about with respect to these early term guarantees you would expect from these sponsors in project financing. Is that a euphemism for construction work and progress?

EDWARD VICKERS

No, construction work and progress really relates more to the contracting industry. This is really an undertaking by the sponsors, either singularly or however it's put together, that the total financing, whatever borrowed funds that are there, are guaranteed until this plant has, in fact, been put on stream and is doing what a feasibility study said it would do. In other words the banks are saying to the sponsors, "I'm financing this on cash flow. Give me a plant that will produce a product so I can sell it, and that I will be prepared to consider looking at the business risks associated with running this later on. It is a pretty tight guarantee."

GIULIO VARSI

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I am from Jet Propulsion Laboratory. It seems to me that rather substantial financial packages have been assembled in the last several years for nuclear power plants. A question I would like to ask of Mr. Vickers is, what is the difference between that kind of financing and what you would foresee for coal power plants. Is it just the fact that time has gone by and financial climate plans have changed, people have become smarter or is there a fundamental technical risk?

EDWARD VICKERS

I don't say that it is necessarily all that different, technically but by in large, this is the power generating facility. The nuclear fuel, the financing of it, has, in fact, become a bit of a problem, but initially this was a whole contained unit here. The uranium was incidental to raising of money for it. Whereas in the use of coal, a significant amount of the capital going into it can be differentiated into producing a raw material and then the utility building the generating station. I think that is why we do make this separation. We see entities in which we can finance, in different ways, and that's why I'm drawing up the distinction and separation of it.

GIULIO VARSI

Ultimately, does that mean that the risks involved in financing a nuclear power plant were deemed to be less than the risks that are considered now for a coal power plant.

EDWARD VICKERS

I don't think you could necessarily draw that conclusion. First of all, most of the nuclear power plants financing was done on the basis of the utility companies bound sheet, which in turn was spreading the risk over the whole of their assets. Here we are talking about the financing a mine, which has a single purpose--to supply coal to one or more utilities. I don't think it's the way the risk was perceived; I think it was a structural thing that was taken place and how it was financed -- it was part of a pool funds. Here we're talking about specific venture financing.

RUSSELL BARDOS

I'd like to add to that if I could. I think what was just pointed out to Mr. Vickers hits the nail on the head in that with the nuclear power plant the cost of that product, the electricity, was spread over user base. Given a high BTU gasification plant there is no rolled-in pricing. The same thing doesn't apply. The risk to the lender is that, if it fails, that financing can't be spread over anything that can be recovered. This is why the Government is looking at incorporating soon the loan guarantee program. It's a big difference between those two things.

MARTIN MATTES

I am with the California Public Utilities Commission. I'd like to ask Mr. Vickers whether he would consider that, in the context of project financing, an arrangement that would guarantee, at least to some extent, the financial communities investment in a project of the kind we are considering. Would the financial community be willing to accept a lower rate of interest on their investments than they receive in a typical industrial loan arrangement?

EDWARD VICKERS

I have just described to you a higher risk financing. No, fundamentally the risk of resource financing, or any major capital project financing, must be bracketed into a relatively narrow spectrum, the banks, I think I emphasized, really cannot take an equity risk so that they cannot let their ranges of rates move all that great because of a risk differential. It either, for all intent purposes, is financible at the market rate, or it is not financible. If you go to the extent of giving me some US government paper that is guaranteeing it, then we can talk different rates, but normally that is not the case. Increments of support, help, but they are basically used to build a credit, rather than change the rate structure.

MARTIN MATTES

A second question I would like to ask is whether, along the same lines, you'd consider that a project financing arrangement would justify a reduced rate of return on the equity portion of the financing, below that rate of return on equity, which is given to the utility generally?

EDWARD VICKERS

I don't think so. I want to clear up maybe the little misconception, project financing is distinguishing perhaps between a low risk and a high risk-type of venture. What we are basically doing, when we talk about project financing or cash flow financing, is trying to mobilize a credit block, be it from the suppliers, be it from the purchasers, maybe its even from the equipment manufacturers. We are trying to build a credit around an entity that now does not exist. That really is the activity. The sponsors will be taking a fairly high degree of risk, even though it's gone through project financing, I think they will probably be taking a greater degree of risk for perhaps a shorter period of time.

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JOHN SPAULDING

I am with Kaiser Engineers. Most of the discussion at this conference has been in the realm of microeconomics. However, the primary impetus behind utilization of coal in California is the macroeconomics, the balance of payments and the reduction in the purchase of oil from other nations. Inasmuch as Mr. Bardos is the only Federal Representative on this particular panel, could he comment on this aspect how might Federal Government be willing to move in this area, other than just in the straight technology areas, as to alleviate the economic burdens in the State of California and, in a secondary sense, solve many of the problems that are facing this country, primarily the inflation and the employment, which are primarily oil-related.

RUSSELL BARDOS

If I could do that, I don't think I would hold the job I have. That's no small order. There are many factors as you have heard these past 3 days. We've addressed the technical side, quite a bit, in what is available, what can be done? From my remarks, I think what one can do today is very limited, from a technological standpoint of what is available, low risk wise you can move out with. The Federal Government can mandate that there shall only be 5 million barrels per day imports, or 7 million. This is a number that is being termed as a goal in the NEP. What would happen if that were the case? If you restricted that oil import, I think we would have disastrous results in this country, because we are not ready for the consequences of that. We are not ready with something there now technologically, from the financial sector or from the environmental sector, to fill that gap. The Federal Government can support projects. They can, for instance, go into the financial support of the Wesco, the LNG or the El Paso Gas Projects. They can build liquefaction plants, but at the same time, so you build one and eventually you can overcome all of the technical problems and all the other problems that are involved with them, you still come down to that bottom line you still have the product that still isn't competitive with the fuel oil that you

are importing, or even limiting imports on, or that you are getting out of the ground in this country. It's still not competitive with natural gas, that currently is being sold, and even with deregulation and the price is expected by 1983, 84, or 85, it still wouldn't be economical unless the government paid for a good portion of it, if not all of those projects. The capital portion is one big chunk that doesn't have to be written off.

On the WESCO Project (I'm going to take the freedom and indicate some numbers), out of the total cost of plant, I believe there is about 400 million dollars that goes into just cost of capital, the interest portion of it. Government, I don't believe, even though there is a big bank there, and its all in red, can support too many of those projects. Its not a simple answer. Industry is going to have to do it on their own, with some incentives, with some support from Government, but at the same time they'll do it when the time is right or when they see the marketplace out there, where the fuels are competitive. They won't do it before that. That's my personal view.

MICHAEL ROGOZEN

I am with the UCLA Environmental Science and Engineering and Science Applications. I have a question for Mr. Vickers. You said one of the things you consider in evaluating risks of a mining venture is the reserve mineable from an environmental point of view. That raises an interesting question. Do you see banks as having a de facto regulatory role, in that you won't accept a certain risk, if it is apt to meet with opposition on regulatory grounds? In other words, you won't finance a project if the risk seems high. If it seems that it won't fly because of regulations, do you have an affect on the project design or components?

EDWARD VICKERS

No, I don't think so. What I was really emphasizing is the uncertainty element of it, once we quantify the degree of risk,

we can determine how much support we need and how much we are willing to take ourselves. It is more of a quantification exercise than it is to how this risk is perceived. Getting a handle on it, is in many of these areas, the very, very difficult part. When I said that the mining reserve was there, what is the likelihood of the mining or it would be interrupted. We are trying to get a handle on that in some way, and then measure who should take that risk and how can they cover for that risk.

SESSION XI

THE REGULATORY SYSTEM

THE PRESENT REGULATORY SYSTEM:
A UTILITY PERSPECTIVE

M. D. Whyte

Manager, Electric System Planning
Southern California Edison Company
Rosemead, California

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ABSTRACT

The California Energy Commission was created, in part, as an effort to reduce the complexity and uncertainties of licensing electric generating facilities. Instead, siting and licensing efforts have been stymied, and the uncertainty of future energy supply has increased. Various regulatory agencies have promulgated unrealistic and sometimes conflicting regulations that unduly complicate power plant siting within the State. Past policies of the Public Utilities Commission frustrated utility efforts to construct needed base load generation by limiting utilities' ability to finance such facilities.

* * * * *

It is an often stated truism that no one wants a power plant in their backyard. Today it seems that everywhere is someone's backyard. And yet, in spite of our desires to have power plants built some place else or not at all, there is an inescapable reality which all Californians must recognize and accept. It is that, in spite of all of our efforts to conserve electricity, our collective demand for the versatile product continues to grow, and this in turn means that sites for new power plants need to be found.

Prior to the Arab Oil Embargo, the rate of growth in electric demand was over 8% per year in Edison's Service Area. Due to increased prices, conservation efforts, and their expected future impacts on consumption, Edison has reduced its forecast rate of growth of electric demand to about 3.5% annually over the next 20 years. The important point to note is that, even with significant conservation measures and higher electricity prices, the rate of growth in electric demand remains positive. In Edison's Service Area, even the present relatively modest growth rate means we must add 500 megawatts of generating capacity each year throughout the 1980's in order to maintain reliable service. When coupled with the need to replace power plants that have outlived their usefulness and the need to switch from scarce oil fuels to coal, nuclear, and other sources of energy, these facts add up to one conclusion--if we are to maintain our standard of living and offer more opportunities to the economically disadvantaged, we must have a system for

assuring that new electric generating plants are sited and built in time to serve public need. My concern is that the present system may not reach timely and successful siting decisions for any power plants.

In the early 1970's, the California Legislature began to address the challenge of designing a regulatory system to assure that needed power plants would be sited and constructed in time to serve public demand. The legislature recognized that the then current system of multiple agency review of power plant siting applications, often in sequence, could no longer be tolerated. An example of the regulatory morass surrounding the siting process was the difficulty Edison faced in securing government approval to build San Onofre nuclear generating station Units 2 and 3. For the San Onofre Project, Southern California Edison had to obtain over thirty separate permits. It took my Company over six years to get permission to start building the San Onofre Project. This extended regulatory time resulted in higher costs to the public, and, by increasing uncertainty, added to the difficulty of providing a reliable supply of electricity to the public.

To break the regulatory "log jam" that threatened to block the siting of needed power plants, the legislature, in 1974, with broad support from environmentalists and utilities, passed the Warren-Alquist Energy Act to create the Energy Resources Conservation and Development Commission, commonly called the California Energy Commission.

Prominent among the ambitious aims of the Warren-Alquist Act was a streamlined power plant siting regulatory process. It included several goals endorsed by Edison:

- o It had predictability. The two-part site review, the Notice of Intent (or NOI) and the Application for Certification (or AFC) had a definite beginning and end.
- o It consolidated the state's role in power plant site regulation. The Energy Commission's Certificate was to substitute for "...any permit...required by any state, local, or regional agency, or federal agency, to the extent permitted by federal

law." It was to be a "one-stop" siting agency.

- o It contemplated a system of public participation designed to avoid unreasonable delays. Alternate sites proposed by a utility were to be preliminarily screened for suitability in a relatively informal notice of intent process, with formal, detailed review waiting until the AFC, when one site and facility proposal would be put forward.

These statutory goals convinced Edison that the proposed power plant review process had a reasonable probability of reaching successful and timely decisions on where and when new power plants were to be built in California. However, as with many other laws, the various interpretations of intent have caused wide differences in the application of the law. As I hope the following review of the goals of the Warren-Alquist Act will show, there is a vital need for reform of the Energy Commission siting process if it is to fulfill the promise of the law and the public's need for a power plant siting process that works efficiently.

First, in the opinion of many, the Energy Commission has not, as yet, successfully implemented the Warren-Alquist Act goal of a predictable and certain siting process. In order to begin the first half of what can be a three-year siting review by the Energy Commission, a utility must file a NOI to construct a power plant. The contents of the NOI, as described in the Warren-Alquist Act, are geared to provide the level of information needed to assess the suitability of at least three alternate sites which an applicant must put forward. In interpreting the law, the Energy Commission has adopted regulations and practices which have greatly expanded the informational requirements of the NOI document beyond what we contemplated was intended in the law, and which, therefore, have delayed the start of the NOI process for several major projects.

The chronology of Edison's NOI for its 1290 MW Combined Cycle Project is an illustration of my point. On August 10, 1977, we submitted a 1,000 page NOI for the project covering information on each of four alternate sites proposed for the plant. According to the Energy Commission's regulations, the staff of the Commission had thirty days in which to review the adequacy of information presented. At the end of that period, Edison was notified that its NOI was "deficient in almost all technical areas". It took another month before we received a staff statement identifying the areas of

inadequacy. These included such things as the permeability of soils in the path of potential fuel spills if retention dikes around storage tanks were to fail, to the impact of the purchase of water from the Mojave Water Agency, whose source is the State Water Project, on the propagation of sport fish in the Aqueduct. In all, there were some 185 major items of information listed as missing from the NOI, items which we feel are not required or necessary according to either the Warren-Alquist Act or in Commission regulations interpreting the law. Our Amended application was finally accepted in March, 1978. Together with the fact that there is likely to be a hiatus of undefined length between the approval of an NOI and start of an AFC, while an applicant copes with the conditions placed on the NOI, the record of the last three years shows that there is a need for reform in the NOI procedure.

To remedy this situation, Edison, together with other utilities, is supporting legislation to make it clear that the NOI is in fact, what the Chairman of the Energy Commission has referred to as a siting "reconnaissance" effort. We believe that by reducing the scope of the NOI, both in what is required to start the process, and in the level of information required during the course of the NOI, to that originally contemplated by the Warren-Alquist Act, predictability and timeliness will result. Applicants should not be required to spend the time and money necessary to provide design level information at the NOI stage.

Another major goal of the Warren-Alquist Act was a "one-stop" permit review wherein the many overlapping and sometimes conflicting policies of government agencies could be balanced and resolved in favor of the overall public interest. Examples of the need for an agency with authority to balance competing public policies abound. Let me mention just two critical areas, air and water quality.

As I am sure you are aware, the state has identified the Air Resources Board (ARB) as the agency responsible for setting state air quality rules to conform to national standards as interpreted by the Federal Environmental Protection Agency. The ARB and local air quality agencies, such as the South Coast Air Quality Management District (SCAQMD) have proposed or adopted rules which could prevent the siting of any new coal or other fossil-fueled power plants in most areas of the state.

Edison presently burns imported fuel oil with a sulfur content of 0.25%, the cleanest burned anywhere in the United States. Yet, now a rule proposed for adoption by the ARB would require that sulfur content of boiler emissions be

reduced to less than that of 0.1% equivalent fuel. While Edison estimates the cost of this reduction would range from \$100 million to \$500 million per year, there has been no proof that the reduced sulfur emission rule is necessary from a public health standpoint.

Another rule recently adopted by the South Coast Air Quality Management District would require that power plants reduce emissions of nitrogen oxides (NOx) by 90%. NOx emissions from Edison power plants are already low due to NOx dispatching, which preferentially loads low NOx emitting equipment, and combustion controls. Edison estimates the minimum cost of developing and implementing the technology required to meet the 90% NOx removal rule, just for existing plants, will be over one-half billion dollars, if it can be done at all. Edison questions the cost benefit of such a drastic restriction in NOx emissions.

It is important to emphasize that the expenditures to meet the NOx and proposed sulfur rules will be required to control emissions from oil-burning generating equipment much of which is over ten years old. The pollution from such sources is estimated at less than 2% of the total emissions in the Los Angeles area. The capital required to meet the NOx rule will not be available for use in developing and demonstrating non-petroleum energy sources such as coal.

If the competing public interests of strict emission control regulations and the need for new electric generating plants are to be objectively balanced, Edison believes the Energy Commission should be given the authority to issue construction certificates for power plants even if air quality agencies have refused to do so, as long as the Commission finds that federal air quality standards would be met. We are supporting amendments to the Warren-Alquist Act to achieve this goal.

In the field of water quality, the state agency with responsibility for establishing rules to achieve goals set in the Federal Water Pollution Control Act is the State Water Resources Control Board. The State Board has adopted a policy on the use of inland waters which provides that fresh water will be used for power plant cooling only as a last resort, that is, when waste, brackish and seawater are unavailable.

The California Coastal Commission, although it does not have the authority to set water quality policy or to impose water quality permit conditions more strict than those imposed by the responsible agency, does have the authority to unilaterally prohibit the siting of power plants on the coast, thereby cutting off access to seawater as a source of

cooling water for power plants. Present Coastal Commission staff recommendations call for designating over 85% of the coast (940 miles) as unsuitable for consideration as power plant sites. Much of the area proposed to be left undesignated and thus eligible to be used as alternate sites in the Energy Commission process, is not suited for siting since it consists of the more densely populated regions of the coast or is located on federal military reservations.

Thus, while one agency has determined that seawater should be used for power plant cooling, another is preparing to block that option. That is why, when it comes to siting power plants, Edison believes the Energy Commission should be in a position to balance the competing public interests of coastal preservation and the protection of vital supplies of fresh water.

Another goal of the Warren-Alquist Act was to provide opportunities for public participation in the power plant siting regulatory process while guarding against unwarranted delay. A key feature of the law was the separation of the site review process into two phases, the NOI, which we envision as a preliminary assessment of the suitability of the use of alternate sites, and the AFC, which is meant to be a detailed review of a single site and the design of the power plant proposed to be built. While both phases of the process should afford ample opportunity for public participation, the NOI offers an especially attractive chance for a broad spectrum of public comment because it is at this early planning stage when all participants can profit most from the public's views of the proposed sites. Such things as the presence of special local circumstances, environmental conditions previously unknown or social problems which local people know best, can be brought out and assessed. We are concerned that the record of the NOI process thus far reveals that it has become an incredibly complex and detailed process that makes participation by the general public difficult at best.

The problem stems from the fact that the Commission staff has lost sight of the role of the NOI as a site-screening process. They have become virtually mesmerized by the desire to deal determinatively with any issue they believe could eventually cause a site to be judged unsuitable during the AFC process. Hence the staff has demanded vast amounts of data on each of the alternate sites, on alternate technologies that might substitute for the proposed plant, on conservation programs that might have been overlooked by the Commission in the course of the development of its official electricity demand forecast, and other matters that belong in the AFC.

In its interpretation of the NOI as a determinative process, the staff has paradoxically frustrated two important aims: first, the goal of the Warren-Alquist Act to treat the NOI as a site screening process, a place where informality and simplicity would encourage "open planning" and participation by the public; and second, the Commission's own aim of reducing the "front end" costs of site reviews so that such costs cannot be used as an argument by utilities that final approval must be granted because of money already spent.

Because of the way the NOI has developed, Edison and other utilities are supporting legislative moves to streamline and simplify the process to reduce the scope of the inquiry by shortening the maximum length of the NOI from 18 to 8-1/2 months, and eliminating the present determinative nature of the proceeding. Detailed consideration of site-specific environmental factors and design features of the proposed plant would be resolved in the APC, which would remain an 18-month maximum proceeding.

We believe the Energy Commission should support the siting reforms we are suggesting because the public interest demands reforms in the current Energy Commission siting process if we are to meet future public demand for electricity. The reforms we are supporting would help to provide a workable siting process with the necessary protections for the many competing public interests that are so sharply focused in a power plant siting decision.

In closing, let me also remark on some areas of concern within the jurisdiction of the California Public Utilities Commission (CPUC). First, there is a need for prompt consideration of the rate relief necessary to support construction of needed power plants. The California Public Utilities Commission (CPUC) took 30 months to decide Edison's last major rate case. Since then, under the leadership of the CPUC chairman, the California Public Utilities Commission has instituted several internal reforms designed to speed up the rate-making process. Our experience in a present pending case is that these reforms are working effectively to reduce lag. This is most gratifying.

Second, in order to coordinate the review of siting decisions by the Energy Commission with the CPUC's review of the financial aspects of a siting proposal, Edison is supporting changes to the Warren-Alquist Act and the Public Utilities Code to require utilities to file for a Certificate of Public Convenience and Necessity with the CPUC concurrent with the filing of an APC with the Energy Commission. These changes, if adopted, would render a decision from both the CPUC and the Energy Commission within 18

months of the date of submission of the application. We think this is in the public interest and will reduce costs to consumers.

My comments today were offered from my perspective as a utility manager faced with the responsibility of finding a path through the present regulatory maze surrounding power plant siting regulation and securing the capital for financing new plant construction. Without instituting some reforms, I believe we will continue to see responsible attempts to site needed power plants, including coal plants, frustrated by bureaucratic inertia.

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AN ENVIRONMENTAL VIEW OF THE REGULATORY PROCESS

Michael R. Eaton

Sierra Club

This has been coal week for those of us here. Last week we had Sun-day Sunday, and on Sunday, coincidentally, the decision to suspend the Sundesert project was announced.

I think these three events define in an important way the outlines of the current situation with respect to energy in California. On the one hand, there is a tremendous public enthusiasm for renewable energy resource development, and a confidence that renewables can contribute significantly to our energy supply mix. On the other hand, we see a profound and as yet growing public scepticism as to the wisdom of relying extensively on nuclear power. In particular, there is a widespread awareness of problems of nuclear waste management. Nuclear industry and federal government attempts to address this problem, both in a technical and public relations sense, have as of yet fared miserably.

Consequently we turn our gaze to coal, each for a slightly different reason and with varying degrees of enthusiasm. An early speaker suggested the metaphor of a dance orchestra as a fitting image for this conference. The tune's there, but the beat's less clear, and each of us is doing a different dance.

One way to account for this divergence is to summarize the mood of the conference as follows: coal seems to be almost everybody's second choice. The utilities would prefer nuclear, the producer states and environmentalists want to trim waste and shift to renewables, and the policy-makers and implementers are caught in the cross-fire, as usual.

This conference has addressed the nuts and bolts of coal utilization: the technical parameters of coal transport, siting, combustion, emissions control, and water supply. It has avoided facing directly what in my view will be a more important factor in determining coal's role in California, and that is the question of public acceptance. Coal has a strong negative public image. It is inevitably pictured as dirty. This negative image has been reinforced in recent months by the public posture adopted by the Sundesert participants during the Legislative debate over an exemption for that nuclear plant. They argued vociferously, before the Legislature and in the media, that coal could not be burned in California without sacrific-

ing our clean air goals. In making this particular theme a cornerstone of the Sundesert campaign, nuclear's proponents haven't done the cause of coal any favor.

Nor has PG&E helped the situation greatly by focusing its sales effort, so far, on comparisons to the Centralia plant and on arguments that the absence of a visible plume from the plant or soot accumulation in its environs makes it somehow clean. The public is sophisticated enough to have learned that dangerous emissions need not be perceivable by the eye to constitute a health threat.

To underscore coal's precarious position, let me use what at first may seem a counter-example. A major California utility carried out a major survey within its service area earlier this year. The poll sought the views of consumers on a number of major energy issues, including future generating options. The results of that poll indicated, for the first time in a decade, that the utility's customers prefer coal to nuclear by a very small margin. This could be taken as a prognosis of clear sailing for coal, but I would caution strongly against such a reading. Coal's preeminence is a function of the erosion of public confidence in nuclear, and little more. Although coal placed first, far less than a majority of respondents selected coal as the preferable generating technology.

All of this suggests to me that dealing with the public is going to be the most important task of those utilities who've chosen to go coal. That task is made more difficult by coal's status as a "second-choice" option.

The vehicle for working with the public during the review stage is the Warren-Alquist Act, and the forum, or battlefield if you will, for the encounter is the California Energy Commission. The Warren-Alquist Act was enacted in 1974 with the following general goals in mind.

First, there was a wide perception of the need to shorten the time for approval of new power plants. Utility industry testimony offered during the debate on the Warren-Alquist Act pointed out that from four to six years were required to secure the local and state agency

permits necessary before construction of a major facility could begin.

Secondly, there was a substantial agreement, in the wake of the oil embargo, that a centralized planning process for energy was desirable. The Energy Commission's role, in this respect, includes responsibility for energy demand forecasting, for implementing energy conservation measures, and for conducting and coordinating energy research.

Thirdly, there was a wide acceptance of the fact that the energy facility siting process must be an open planning process if it is to adequately and efficiently deal with public concerns and avoid time-consuming controversy and litigation downstream.

Unfortunately, one of the disbenefits of centralized decision-making is the de facto disenfranchisement of local groups and individuals who lack the time and financial resources necessary to participate in a Sacramento process. The Act sought to compensate for this by creating, within the Commission but independent, a public advocate whose job is to inform and assist interested members of the public. In addition, the Commission is required to hold some of its hearings in the areas to be affected by the particular project.

These provisions for public involvement are important, but they do not in my view go far enough. In practice, citizen groups have found the Commission's siting process to be expensive, time-consuming, and to require extensive travel. These problems can be mitigated only through a program of public funding designed to reimburse citizen groups for costs incurred in the Commission's siting and other processes. Such programs of public assistance have operated successfully at the federal level for several years, and their impact, contrary to the fears of opponents, has been to speed up the decision process by allowing for the early identification and resolution of environmental and consumer concerns. The Commission's Public Adviser, Carolyn Kemmler, has proposed a similar program for the Energy Commission. Its price tag would be about half that of this conference. It would, in our view, be money well spent. A program of public funding would accomplish far more toward identifying and resolving public concerns about coal use and making possible constructive dialogue, than a dozen such get-togethers as this. I would urge this audience to consider seriously the merits and advantages of public funding.

The Warren-Alquist Act has been in force now for 3-1/2 years. It's been a stormy period, and as many expected, the Commission has had problems getting its house in order. The consensus of support with which the Warren-Alquist Act was enacted has all but eroded away. Mr. Warren's gone to Washington, and Mr. Alquist has had some second thoughts. A major legislative review of the Act is underway, impelled in large part by the Sundersert controversy.

The utility and energy producing interests have embarked on a lobbying effort aimed at shortening the Commission's allowable review periods and redefining the scope and focus of the

two phases of the siting process. I won't attempt to deal with the details of these proposals now, but I would like to offer a few words of advice to those concerned with the future of coal in California. I would like to recall to you Tom Austen's closing comment, which I'm not sure received the attention it deserved. Tom said, more or less, that if utilities, environmentalists and regulators fail to work together to build a coal plant that is significantly cleaner than EPA standards, the dissension that will accompany that project may well mean that California's first coal plant is its last. The Energy Commission stands now as the only arbiter of that type of dissension or disagreement. While imperfect, it stands far above any of its sister state or federal bodies in terms of public participation and, consequently, of public confidence.

It is fashionable in some circles to consider that government is in large measure the problem with respect to energy. There is room for, and need for, reform. But don't forget about the public role in energy policy formulation. Without that public involvement, I believe any energy strategy, plan, process, or major project is doomed to fail. Without full consideration of the views of citizen groups, there will be little basis for public confidence that the result of the decision process is in the public interest.

I'd like to conclude my remarks with two specific comments. First, let me allude briefly to one of the major gaps in this three-day program. I do so not to detract from the efforts of those who've put this meeting together, but simply to counter the inevitable psychological momentum which may induce us to believe that we've done the job or taken care of the problem in these three days. I refer specifically to the absence of any consideration of the land use planning aspects of coal development in California. The Bureau of Land Management is currently involved in the preparation of a master land use plan for the California Desert Conservation Area, one of only two BLM conservation areas in the country. This is a major effort. It will have a fundamental role in directing future uses of the desert, and it will have a precedential importance with respect to the handling of public lands elsewhere. The California Desert has a special place in the hearts and minds of Southern Californians, and surveys have found overwhelming public support for preservation of desert lands and opposition to energy development and ORV use. Sorting out these conflicting values and potential uses will be a major part of any effort to site a coal plant in the desert. BLM is laying the groundwork for that effort, and I think it's very unfortunate that neither BLM nor the citizens working with them in that effort were represented on this program.

Secondly, and finally, I would like to address myself briefly to the request that Jim Walker made of the panel members. Jim asked that we look ahead two years and ask ourselves what we would hope to see accomplished by the regulatory agencies in that time. I'll suggest two--one for the Energy Commission, and to be fair, one for the ARB.

First, the Energy Commission. I think it is essential to the energy planning and decision

process that the Energy Commission solidify and demystify its forecasting process. As anyone who has worked with the Commission knows, there have been no firm answers to the questions of need and conservation potential. The forecasting process is obscure, it suffers from a lack of public involvement, and it's running behind schedule. Since the need question is in most cases the threshold issue, attempting to build an evidentiary record and public dialogue given the current situation is much like building a house of cards--you never know which additional card is going to cause the whole to come tumbling down. I would hope that in the near future the Commission will be able to put its forecasting activities on a more solid footing, clarify that process, and make it a more open process.

My second expectation pertains to the Air Resources Board and in particular to the development of the State Implementation Plan. It seems to me that air issues suffer, like the forecasting process, from a certain measure of ambiguity. In particular, I sense a lot of confusion, both within the environmental community and among industry and utility people, as to the effect of the air constraint in determining the siting of new industrial and generation facilities, urban versus remote siting, the development of cogeneration, and other key issues. I would hope that as the SIP is developed, the ARB and the local boards will be able to educate and involve a broader segment of the public and to define issues and impacts in a way to better facilitate that involvement.

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REGULATORY FUTURE OF COAL IN CALIFORNIA

Mary Nichols

Air Resources Board
State of California

Abstract

Coal has a public image as a dirty fuel and facilities using coal as being among the most polluting sources in any industry. This image has led many to conclude that coal needs special consideration and special regulatory treatment to be burned in California. Nothing could be further from the truth.

The first coal-fired plants in the West were dirty. With the enactment of tough federal laws and local enforcement, these are being cleaned up. New plants, with full advanced controls installed during construction, will be far cleaner even than fully retro-fitted older facilities. New coal burning plants can be cleaner than traditional oil burning facilities.

Once the image that coal is dirtier than other fuels has been dispelled, it is clear that a coal-fired power plant faces no more difficult regulatory tests than other large industrial sources seeking to locate in California or other states with serious air pollution problems.

Regulations requiring pre-construction review of large new sources which without strict controls have the potential to seriously degrade air quality are still relatively new. Projects which have sought to locate in California under these regula-

tions have not found them to be an impossible burden. Although a coal plant has not formally gone through California's permitting process, all of the analyses done so far on a hypothetical coal plant indicate that there are multiple sites where the existing regulatory process could permit location of such a facility. It is certainly too early to say that changes in the process are necessary or even to predict what adjustments might be required in the future.

The shape of future regulations seems clear. Because the exact nature of air quality problems varies among air basins the stringency of some rules, including requirements for emissions offsets, will be greater in some areas than others. The precise amounts and types of needed emissions reductions will be set when the State Implementation Plan (SIP) is presented to the Environmental Protection Agency in January of 1979. Approval of the SIP will further reduce doubts about where coal can be burned and under what conditions. Development of a program for prevention of significant deterioration (PSD) in areas of the State where a sulfur oxide and particulate standards are now being met, including designation of some Class III sites as suitable for an incremental addition of pollutants, will also occur within the next year. At that point, it will be possible to "map" suitable sites anywhere in California, at least from the air quality perspective, with considerable certainty.

NOTE: The complete paper was not available at the time of publication.

SESSION XI: THE REGULATORY SYSTEM

Session Cochairmen: Jim Walker (CEC)

Martin Goldsmith (JPL)

Speakers:

Doug Whyte (SCE)

Michael Zaton (Sierra Club)

Mary Nichols (ARB)

OPEN DISCUSSION BY ATTENDEES

UNIDENTIFIED ATTENDEE

I wonder if there is a fundamental incompatibility between the State and Federal energy policy. When we talk about the need for energy in California, it seems that most of the talk centers around at what rate the demand for electricity will grow and will conservation, in one form or another, be enough to obviate the need for additional resources. You could look at need another way. California is burning a tremendous amount of oil, a resource that could be very precarious by the mid 80s, at least economically, if not as far as availability goes. There is a need for coal or some alternate resource in order to reduce our dependence on oil. I am wondering to what extent the Commission recognizes that as a legitimate need for coal or any other alternate source of power; the need to replace oil fired generation as opposed to the need to meet any future growth.

JIM WALKER

I don't think there is any fundamental conflict between Federal and State energy policy. There is a superficial conflict and it is caused, basically by people looking at the Legislature's and the Energy Commission's recommendation on Sun Desert. They are basically saying, that if you are burning an amount of oil and you can build another nuclear plant, that can displace oil, you are not doing as much as you could theoretically could to reduce

oil consumption. In fact our analyses show that you could achieve essentially the same levels of oil consumption through an alternative resource plan, involving coal, geothermal, conservation and other measures. I think that even in that sense we had a lot of questions. It wasn't a strategy that's in fundamental conflict with the National Energy Policy.

For another thing you know there is no National Energy Act yet. That is still up in the air, and one of the things that I wish the federal policy makers would understand is I would much rather them work on a federal energy policy than a national energy policy. I think that the total national energy policy part of it, is going to be built from the ground up. California has a lot of ideas, Texas does, all the States you probably heard from yesterday do. I think the fundamental regional nature of energy policy has to be recognized at the national level, at the federal level, and they should spend most of the time developing two things: the unique role for the federal government and then the interfaces with regional interest.

SARAH HOFFMAN

I am a representative of local government. I am from San Bernardino County. As a representative of local government I very much agree with Mr. Eaton. The concerns of local citizens must be included in decision making process and join in his praise of BLM's effort to do a land management study for our desert. However, air quality is also of vital importance in the desert region and planning there is also necessary. San Bernardino County has requested ARB's expertise in preparing an air quality maintenance plan for the desert and has been turned down. I think if ARB is truly behind their concern to streamline and coordinate, they might want to reconsider this decision.

MARY NICHOLS

If that was a question, or even if it wasn't, I will respond. San Bernardino County, in a very open attempt to avoid dealing with land use or transportation control issues at the county level, asked the

ARB to take over control of its planning process under the nonattainment planning provisions of the Clean Air Act. That is a task that is impossible for the ARB to take over because of the Clean Air Act requirements, that local government be directly involved in those aspects of the planning that are under the direct control of local government, namely land use and transportation. We so notified the County of San Bernardino and we are attempting to initiate a cooperative planning process between the State and the County.

I would like to use the opportunity while we are waiting for somebody else to ask a question to respond in part to the question that Jim raised.

One thing that I think that the ARB needs to do, within the next two years certainly, is to amend the State implementation plans to adequately meet the requirements of the Federal Clean Air Act, in terms of both nonattainment area planning in various areas which do not meet any of the federal standard, and prevention of significant deterioration in areas of the State that presently are better than the Clean Air Standards. We are internally accelerating our process of trying to develop a plan for areas of the State which we now believe meet the Federal Air Quality standards and to develop a program for identifying areas, which are suitable for some degree of degradation. Under the federal law, there are three categories of deterioration that are permitted, none of which would be down to (or up to depending on how you look at it) the level of the Federal Air Quality Standards. They would still have to be better than that, but there are areas of the state that may well be appropriate for some degree of deterioration and we intend to develop a process to identify such areas with the help of local government.

DALE JONES

I am with the Southern California Edison Co. I wanted to thank Mike Eaton for bringing up the point of public acceptance of coal in California, which I agree with him is very important. I don't know if you were here yesterday to hear Larry Papay's talk on burning coal cleaner than oil, but to summarize it, the idea is to take an existing oil fired plant, convert it to coal and demonstrate advanced NO_x SO₂

particulate, and other control technologies. The objective of this would be to have less emissions after you are done than when you start. Now the question I have is, do you think that the Sierra Club or other groups, like the Sierra Club, would support a program to try to get down to reality with what really can be done and if not, why not?

MIKE EATON

I think that the program that was outlined yesterday does sound very promising. Certainly nothing that we could find fault with.

BOB WEINER

I work with the San Diego Gas and Electric Company. I'd like to direct a question toward Mary Nichols if I could. I picked up on a point that was made by Doug Whyte, in his presentation, in terms of the relative cost of NO_x control. In this sense, it was in terms of NO_x control on our present available energy resources.

Assuming that Southern California Edison is required to meet the 90% NO_x removal requirement, passed by the South Coast Air Quality Management District, by 1982, is this not a disproportionate allocation of electric rate payer's funds, considering that power plants only contribute about 2% of the NO_x in the South Coast Air Basin.

MARY NICHOLS

The figure isn't 2% of NO_x. That 2% figure is deceptive, that's based (I call it deceptive, Edison will disagree with me), 2% number is based on total pollutants emitted. Their share is 2% of all pollutants emitted. Power plants are extremely low emitters of hydrocarbon on a proportional basis. They are substantial emitters of NO_x and I believe that the cost to the rate payers, as compared with other costs of NO_x cleanup, which will be needed to meet Federal Air Quality Standards, is not out of line based on the technology, that, I understand, will be required to meet the cleanup requirements. I, however, would like to emphasize that is based on the assumption

that 90% is the figure that's required. Edison and the Department of Water and Power have appealed to the Board from the decision of the South Coast Air Quality and Management District on that rule and we will be reviewing that at our meeting in May.

BOB MEINZER

We are not going with a single figure, but assuming then that mobile sources are, in fact, the largest single contributor to NO_x emissions in the South Coast Air Basin, I'd like to find out from you what plans are being considered by the Air Resources Board for controlling those types of emissions.

MARY NICHOLS

As you probably know, the Air Resources Board in California has the most stringent standards in the country for NO_x control from automobiles. We have established standards which are substantially in excess of what the Federal requirements on automobiles would be. We have said however, that we don't believe that is the ultimate cleanup that could be expected of the automobile. We feel that we have gone as far as we can go, with existing technology and the auto manufacturers' question whether what we are talking about is even existing technology, but it is at least known technology for cleanup of NO_x emissions from cars. I think that we are going to be moving much more vigorously to control other mobile sources, in addition to the passenger car, I'm talking about trucks, buses and motorcycles. For example, we have got control programs going into effect, in all of those areas, which are going to bring emissions of new vehicles down substantially. We have also indicated that our goal by 1990 is to have a vehicle fleet emitting 50% electric of the current standards. This will mean a substantial number of electric vehicles, we will be producing more business for your power plants and more cleanup will be required.

IKE EASTVOLD

I'm representing the Desert Region for the Sierra Club. There were some concerns which were eclipsed during the Sun Desert NOI, by nuclear issues and financing issues which as Mr. Eaton pointed out

were not addressed in this conference and which seemed to have been sort of forgotten or laid aside since Sun Desert was rejected. Those are the land use planning issues. Those of us that were involved in the Sun Desert proceedings and were concerned about it, were concerned about the regional scenario for energy development that would have been crystalized by the Sun Desert Plant. Being essentially the first major nuclear facility in the eastern desert with the Vidal Project and LADWP's Eastern Desert Project waiting in the wings. It seemed that Sun Desert was going to fly, that several of these other plants would have of course followed the lead, and we would have a major nuclear onclave with transmission lines across virgin parts of the desert and substantial commitments of scarce desert water resources to these plants.

These regional implications were never really addressed by the NOI approach. I don't see that in preparing for coal in the State of California that we really have much of a different situation. We have PG&E coming in with a few sites up in Northern California and obviously everything that happens in PG&E's NOI is going to affect us down here in Southern California. It has a regional impact and yet its not being approached as a regional issue. It is a regional issue. We have Edison talking about getting ready for Vidal at Daggett. Why have we settled on Vidal? Why are we looking only at the desert. Why aren't we looking at the Southern California Region or why aren't we looking statewide. It was always my understanding that the Warren Alquist Act provided some responsibilities, whereby the Energy Commission had to do statewide facility siting land use planning.

I would like to ask Mr. Walker how he sees these responsibilities today for regional and statewide land use planning as we approach the coal question. I'd also like to bounce it off Doug Whyte from Edison in regards to regional perspective and what Edison might be doing to get a regional perspective on this Vidal proposal. I'd also like to say that we very much appreciate the fact that Southern California Edison's NOI, for the combined cycle facility, does pick sites that are considerably separated in distance and represent

different environmental and geographical areas in Southern California. Whereas SDG&E's NOI, we were stuck with essentially three sites in California within maybe 40 miles total distance. They were all using the same water, the same transmission lines systems; no matter which one you chose, you were going to get the same results. I would like to bounce that off Edison and Mr. Walker if I could.

JIM WALKER

Maybe I can start off. I think to a limited extent, it is addressed in each Notice of Intent. For example, in Sun Desert the commission approved the three sites but only for one facility; basically saying that they all depend on the same water and other resource base, so they weren't independent locations. In that limited extent they explicitly recognized some of the regional concerns. The way we are approaching it in looking at the cases now is much more explicit. Namely, if we are looking at the PG&E Fossil 1 and 2 Case, the staff has established a Northern California supply strategies team with a very substantial portion of our staff working on it, including the whole set of environmental constraint subgroup. They are looking at not just Fossil 1 and 2 but Pittsburg 8 and 9, the geothermal development of the geysers whole series of other plants and how those will affect perhaps the ultimate carrying capacity of a site, at Montezuma, of the Northern San Joaquin Valley, etc. I think that we recognize, really based on the analysis we did for 1852, of how you can go about, what we call a locational analysis and regional and environmental constraints. I think we will be doing the same thing. We do have a representative working with the BLM on the desert planning, so for the same complex of Southern California cases, the Edison Case, any new filings that we may have down there, that some approach to the extent of our staff limitations, will be incorporated. In the other areas we will be working with the Air Resources Board and State Implementation Planning where there is some explicit regional planning operations going on. So it is something we did, really in the first years of the Commission's existence, it is in the law, we had some ideas about what it meant, we didn't really know how to operationalize it. I

think we do now, and I think that we will be seeing each case will be done in the context of the total development pattern for the region. I won't promise everything, but I think that we are going in that direction, explicitly, in our internal planning.

DOUG WHYTE

Yes Ike, on the subject of air combined cycle NOI, we did spend a great deal of time and it was a deliberate attempt to try and regionalize the coast and the inland siting for the 4 sites that we have on the NOI.

On the subject of the Vidal coal plant that you mentioned, I just want to point out that we have not submitted an NOI, we are not to that stage yet. We're merely assessing the possibilities and the Vidal site was one candidate site that was mentioned, because it happens to be fairly close to both a railroad and water, which are two of the essential ingredients that we need to site a coal plant. There is another little wrinkle there and that is that Edison owns a piece of land out there.

JIM CONGER

I am with Chevron Research Company and I'd like to comment on Mary Nichols observations about State government. You mentioned that the recent operation of the uncoordinated state bureaucracy's interacting and bickering with each other and generally the lack of progress, showed state government operating the way it ought to be. I disagree with that. Implicit in your statement is the assumption that we have time to waste.

One thing we haven't talked about in the discussions here, was the urgency with which the State of California and the Nation as a whole, come to grips with the energy problem and that's partly the coal issue. We just don't have 5 years, 6 years to waste developing and getting going on a single project. Right now, even a precursory look at the American energy situation shows we are importing almost half of our oil and that half could be cut off at any moment. We just don't have time to waste for that kind of bureaucracy.

MARY NICHOLS

I was being slightly cynical, but I'll take you on despite the overwhelming support that you appear to have from the audience.

We do not face an immediate crisis about burning coal in the next 5 years. We have a glut of oil in California in the next 5 years. We recognize our role as part of the national energy picture and our obligations to help with the process of shifting away from the extensive and excessive reliance that we have on foreign oil, if the solution to that is to abandon existing legal obligations to meet environmental standards, and to abandon existing commitment to local, state and federal government processes that are in place, then I think we should be prepared to face that.

I personally am very willing to take that risk and I suggest that most of the people of the State are also.

DONNA PIVIROTTO

I'm from JPL. One of the reasons we are having this conference is to prepare for a workshop which will presumably try to address the issues of what the State can do to help make it possible to use coal in California. One of the problems, when we were doing a geothermal study, we noticed the lack of coordination or understanding of what coordination was required, between the various state agencies and between the state agencies and the federal agencies and local agencies, etc. I'd like to know if: 1) you feel that the communication methods are adequate to address the problems that we expect to find with coal and the regulatory necessities, and 2) if they are not adequate, are there plans being set in motion now for building up these communication channels. I'd like to address that Mr. Walker and Mary Nichols and maybe to Mr. Whyte who is kind of caught in the middle.

JIM WALKER

I basically support Mary with certain cautions. Namely, I think it's possible and I think with a lot of diligent effort on the part of the State agencies, it can work. It really will take a

commitment upon all of the state agencies to not try to defend their own turf too much, to realize that there is going to have to be some give and take to realize that the Energy Commission has a non-single purpose in the environmental energy balancing role. We will sometimes be taking on other agencies, etc., but I agree with her, although I have my fingers crossed and I realize that the Energy Commission and myself personally the staff will have a tremendous responsibility in making the system work. We have a lot of our resources projected for better interagency coordination because now we know what it is in a non-motherhood sense. We have a much better idea of the specific task, regulatory proceedings which what we are going to have to work on to get done in a reasonable time frame to provide this sort of coordination. We can always talk about more coordination, that doesn't help.

MARY NICHOLS

Coordination takes accuple of things, at a minimum; it takes commitment and it takes resources. I think the commitment has been there for a long time and certainly the intensity of public issues, that have focused a lot of attention and pressure on State government, such as the recent Sun Desert decision, forces other agencies besides the Energy Commission to get involved and to commit themselves to the Energy Commission's proceedings in a way that perhaps the normal course of events might not. To do an adequate job of feeding the Energy Commission the kind of information it needs in its regulatory process, at the time that they need the information, the Air Resources Board has to have available to it the information, the staff, the expertise to give the Energy Commission what it needs. When we started out three and one half years ago, the Air Resources Board did not have a unit that was even specifically involved in energy issues. We had a Stationary Source Control Division which was involved in development control regulations for all stationary sources, including power plants, but the level of knowledge, interest and involvement that the ARB had had with power plant issues and, certainly with anything other than existing power plants that we knew about, were just about nil.

In short period of time, we have brought on a large number of staff, redirected staff efforts, and developed a substantial body of information and expertise. That has been a process that has taken some time. I don't under estimate the difficulties of getting bureaucracies to get beyond turf preservation issues and into a really streamlined coordinated process, but the message has come down clearly from the administration that that is what is wanted at the policy level. The Governor's Office has convened a working group of policy level representatives, of all the agencies that have interest in the energy field, that gets together regularly simply to discuss upcoming issues; not to make decisions or to debate specifics, but at least to identify what the issues are and make sure that staff is available to work on those problems. I think the process of coordination is under way and I think its going to keep on getting better.

DOUG WHYTE

I'd like to speak to that if I may. I think those of you who have been listening here, who may not be familiar, are now becoming familiar with the types of problems faced by the utilities, daily, in trying to get something like a power plant sited in this state. ... time goes on the State governmental agencies are becoming more informed, are having greater expertise, but this very process is becoming more and more complex. I'd just like to read you an excerpt from our NOI, which is going on right now. We received this just a couple of days ago, it is an information request. "Provide a copy of the studies, reports and other data used in evaluating the vocation extent, type of movement, expression and ages of movement of the map lineament described in Supplement Item 14E3, especially southeast of the site where Dibley shows older aluvium in linear contact with granitic basement, including that data and clearly legible trench logs obtained from exploratory trenches on or near the Emerson Fault and its splay.

DOUG WHYTE

Now the only thing I'm trying to say here is, this is an NOI which we believe should be site screening procedure. I really

don't know where the public can be in this sort of a proceeding. We're getting technicrats and experts all over the place and in answer to your question, Jim, on what I'd like to see two years hence, I would like to see an approved APC in the State of California, where a power plant could start construction.

SUSAN LUCKY MOORE

I want to say in defense of the Energy Commission that I have attended a good many of their workshops and meetings. I like the way they're giving the public participation in this. They are doing a very good job, I've been allowed to sit there at tables opposite the Edison people and the Energy Commission staff and chip in my two bits whenever I want to. If I have a question to ask I'm allowed to and they talk back to me and I can talk back to them and I like this kind of interplay. I feel, I learned that they are nice people even if we are adversaries perhaps, and they are reasonable in the way they talk to me and enjoy this kind of interplay. I think the Energy Commission is really a leader in giving the public this kind of participation. I appreciate it. But I had a question too. If we do have coal in California, I have no objections to the use of coal as long as its clean. But who is going to make it clean? What agency is going to say you have to have all these wonderful control that we have been hearing about here at this meeting? Are they going to say it firmly, or are they going to say, well you only have to have so much control that you meet the standards? Is that all that is going to be required, because in the desert there is a big difference between the air that they have out there and what you have in the city. The standards were designed to help polluted areas and take care of their problems, but they don't keep our air like it is in the desert, where it is still good. There is a gap I'm afraid that the utilities think that is a good job for power plant pollution. They can fill it down to the standards. But we don't feel that way about it. We care about that clean air and a lot of us are living out there for our health, for that very reason, we don't want that destroyed, even if its better than the standards,

we want it kept up. If they would put best available technology on coal plants they might place in the desert, fine, but we want the best, we don't want these endless arguments about, well, sorry but the pollution won't bother you, it's going up into the second wind layer and that is going to blow some other direction and when it comes down again you won't even know. There won't be that much pollution that it is measurable!

All the same, its going to make the sky gray and its going to change the quality of the air, even if it doesn't kill the people. The standards I have been told are made for people whose health isn't good. They won't die under the standards, but they do go out to the desert to live because they can breathe more comfortably and they can live longer out there. In the Morongo Basin, where I come from, we have 52% of our permanent resident families living there for health. We're worried about these power plant projects that are being suggested in our vicinity. I'm taking part in the NOI about the Edison combined cycle for this reason. We figured there are some areas that should be protected for human health benefits. That's very important land views.

MARTIN GOLDSMITH

I would like to respond to that because that is a very serious and a very basic issue; we are speaking of balances between areas. In previous days we've had considerations of how about the people in Utah and how about the people in Los Angeles in their conflicting issues.

This is not a new issue, as far as desert air quality for example, and let me make a couple of observations. As long as I dwell on this basin, let me offer a little defense about it. It's good that people can go to the desert for their health. It's fine, but let me point out that you place an inordinate burden on the balance of us.

Your electricity is currently being produced for the most part in this basin and I'm breathing your fumes. The gasoline that you burn to make the long traverses across the desert is refined in this basin and I breathe your fumes. All of your manufactured goods, likewise come from this basin. You have got to make a little trade here. There is no perfection. Some of us are going to have to share other people's burdens, in fact hopefully we all share, but we can't I think take a certain part of the world and set it aside and say that the folks that are fortunate enough to be able to live there are going to have it perfect and everybody else has to put up with it.

It's very difficult but we can't just say the desert has to remain absolutely pristine forever, all of it, because, good Lord you just can't do that, it seems to me.

SUSAN LUCKY MOORE

I'm only asking for a small part of it. You have places where you specialize in industry and there should be places where you specialize in health too. That is only logical.

GEORGE ANASTIAS

I'm from San Diego Gas and Electric. I have 3 very brief questions. The first is clarification from Mary Nichols that the 1990's strategy is 50% of the vehicles in California be powered by electricity.

MARY NICHOLS

Cars sold in 1990 would have to meet an emissions standard, 50% of the present standard, on the average some number of those would probably be battery powered.

GEORGE ANASTIAS

Is that part of the state implementation plan?

MARY NICHOLS

It's not part of the implementation plan yet, but I expect it will be, its already been included in the Bay Area's recommendation.

GEORGE ANASTIAS

Thank you. A follow-on questions to Mr. Whyte from Southern California Edison. Were you aware of this, as far as load growth? I have some additional questions as well.

DOUG WHYTE

The answer to your first question is no, and I didn't hear the second question.

GEORGE ANASTIAS

Then a question for Mr. Walker, since there is this extensive coordination between the Air Resources Board and the Energy Commission I would like to know where in the 1852 forecast this load appears.

JIM WALKER

It's not in the 1852 forecast.

GEORGE ANASTIAS

Thank you.

JIM WALKER

That concludes the question period and I want to thank the panel members and also express my personal thanks to JPL and all the participants here.

DAN SCHNEIDERMAN

I thought I would sum up the 3 days. I wish to thank all of you who attended and those especially who contributed, the speakers, the panelists and chairmen. I also want to thank, publically, the agencies that supported this operation. We have I think at the beginning, noted that this is just the first step of a series of things we intend to do at JPL, relative to the use of coal in

California. This first step was initiated by NASA, the National Aeronautics and Space Administration, that is the JPL Contractor for the Government, of course the Department of Energy, Jim here was a big supporter, I hope, I think still is, of the idea and the Department of Energy. Thank you very much for attending.

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Banquet Address

PROBLEMS IN AND PROSPECTS FOR INCREASED COAL USE FOR CALIFORNIA AND THE WESTERN UNITED STATES

Hal B. H. Cooper, Jr., Ph.D., P.E.*

Associate Professor

**University of Texas at Austin
Department of Civil Engineering
Austin, Texas**

Abstract

Coal use will become increasingly important for California between 1980 and 2000. A level of between 20,000 to 70,000 megawatts of coal-fired electric generating capacity may be needed for California by 1995, depending on demand and availability of other fuels. This electric generating capacity level would require 70 to 220 million tons of coal per year by 1995, mostly from Utah or New Mexico. An additional 10 to 30 million tons of coal per year could be used in synthetic fuels production for use by existing industries and in transportation in urban areas to minimize potential air quality problems. Extensive coal use for California could require a capital investment of 20 to 70 billion dollars, of which approximately 15 percent is for air pollution controls.

Siting capabilities for coal-based energy production in California is limited by both air quality and water resource constraints to a maximum of 50,000 megawatts under the most optimistic conditions, or 70 percent of the maximum requirement. More realistic estimates of coal-based energy production inside California are 3,000 megawatts by 1985, 16,000 megawatts by 1995, and 22,000 megawatts by 2000. Realistic policies and regulations are needed by California regarding in-state siting of coal-based energy facilities, and by adjacent states in terms of enacting fuel severance and energy export taxes. Coal-fired power plants built in California will be largely in the Northeast Bay Area, the Sacramento Valley, on the Northeast Plateau and in the Southeast and Mohave Desert regions.

California's program of conversion to coal is a somewhat smaller scale version of the one presently underway in Texas, where both states have heretofore been largely reliant on natural gas. Texas' program of coal conversion resulted from a conscious decision to reduce reliance on natural gas. California's interest in conversion to coal resulted from the passage of laws restricting future nuclear power development at a time of decreasing

natural gas supplies. The two states may be in conflict over natural gas allocations to either the Houston or Los Angeles air quality regions as the result of increased coal use for electric power generation in Texas to free previously committed natural gas supplies.

A major commitment to coal use for California will require effective, uniform, and realistic environmental policies and regulations by all affected state agencies to facilitate in-state siting of coal-based energy facilities. The proposed New Source Performance Standards for sulfur oxides emissions from new coal-fired power plants will require uniform application of Best Available Control Technology. These regulations will tend to make low-sulfur Western coal less desirable as a fuel in other parts of the country because of the added transportation costs. The result will be that coal will become more economically attractive for use by California. A major effort is needed to develop more effective and less expensive control technologies for coal combustion and conversion facilities.

INTRODUCTION

National Problem

The United States is facing an increasingly serious problem of decreasing availability and increasing price of petroleum and natural gas from domestic sources. The United States is presently importing almost 8 million barrels per day of oil at a growing drain on the national balance-of-payments of about 45 billion dollars last year. The increasing need to import oil from foreign countries is acting to worsen inflation, increase unemployment, jeopardize national security, and subject the nation to possible economic disruption by the potential threat of supply disruptions.

The nation is also facing potential shortages of natural gas in many of the consuming states because of recently decreasing production caused in part by

*Also Environmental Studies Coordinator, Center for Energy Studies, University of Texas at Austin, Austin, Texas

the continued federal regulation of natural gas prices at artificially low levels. Natural gas can be imported into the United States in either super-cooled liquefied tankers or by pipeline from Canada or Mexico, but in relatively limited quantities. It may also be possible to produce synthetic natural gas from coal by gasification in the future, but it is not being presently done on a commercial scale in the United States.

The United States is faced with a serious problem of the maldistribution of domestic energy supply and demand. Oil and gas combined constitute less than 9 percent of the total national energy reserves but presently constitute over 75 percent of the total national energy consumption. On the other hand, coal comprises only 18 percent of the national total energy consumption, but constitutes almost 85 percent of the national total energy reserves in the absence of breeder reactor development.

Regional Problem

The Western United States contains the major proportion of the nation's energy reserves with the boundary at the Mississippi River. This region consumes less than it produces because of its generally lower population density with net energy exports to the more populous Eastern states. The region exports substantial amounts of energy to the Eastern states in the form of natural gas and uranium for nuclear reactors, and is exporting increasing amounts of low-sulfur coal to the East, South, and Midwest.

The Western states (particularly Texas, Alaska, Oklahoma, New Mexico and California) produce more than half of the oil from domestic sources and over half of its natural gas. The Western states contain about 55 percent of the nation's total coal reserves and more than 70 percent of its low-sulfur subbituminous coal, especially in the states of New Mexico, Utah, Arizona, Wyoming, Montana and Colorado. Large deposits of low-grade lignite coal are also present in North Dakota, Montana, Wyoming, Texas, Louisiana, and Arkansas.

The Western states have over 90 percent of the nation's uranium reserves, particularly in New Mexico, Utah and Wyoming. These uranium reserves are projected to last only 30 to 35 years with present light water reactor technology, unless the proposed liquid metal fast breeder is developed. The Western states also contain substantial deposits of thorium that could be used for thorium-cycle gas-cooled fission and breeder reactors.

Perhaps most important, the Western states contain the great proportion of the nation's potential reserves for advanced energy technology development. Over 95 percent of the nation's geothermal energy resources are contained in the Western states, especially in California, Arizona, New Mexico, Utah, Idaho, and Texas. The four Southwestern states of California, Arizona, New Mexico and Texas are the region of greatest solar energy insolation intensity and have the greatest potential for its development. California has taken the lead in development of advanced energy technologies, with a 1,000-megawatt geothermal plant

in operation at Geyserville and a 10-megawatt demonstration solar thermal power plant under construction near Barstow.

CALIFORNIA SITUATION

The seriousness of the present national energy situation can perhaps be no better illustrated than by the fact that the present Conference of Coal Use for California is even taking place. The idea of holding such a conference would have been unthinkable 10 years ago, or even 5 years ago. There has been considerable reluctance in the past in using coal in California because of the state's very serious air quality problems, the lack of suitable emission control technologies, and the heretofore large-scale availability of cleaner burning natural gas and fuel oil at relatively low prices.

Nuclear Power

Up until about 1973, it was generally felt that nuclear power would become the predominant future energy resource for California, in part because it would not add conventional air pollutant emissions to aggravate the state's already serious air pollution problems. However, serious questions were raised by environmental groups, state officials, legislators, and concerned citizens about the potential suitability and wisdom of a major future commitment to nuclear power. The adverse problems noted regarding nuclear power development included the following questions: 1) the safety aspects of nuclear reactors; 2) the small but finite possibility of large-scale radiation releases from major accidents; 3) the rapid recent escalations in nuclear power plant capital costs; 4) the prolonged regulatory delays in the licensing process; 5) the lack of resolution of the radioactive waste management and disposal issue; 6) the possibility of a relatively limited resource base in the absence of breeder reactor development; 7) the fact that nuclear energy is largely limited to generating electricity in large central plants; and 8) the greater water-intensiveness for waste heat dissipation of nuclear as compared to fossil plants of comparable size in the generally water-sparse State of California.

The whole nuclear issue reached a climax during the spring of 1976 with the so-called Proposition 15, or the California Nuclear Power Plants Initiative. The passage of this Initiative would have seriously restricted future nuclear power plant development in California until such time that at least some of the above questions were resolved. The California Nuclear Power Plants Initiative was soundly defeated by the voters in California on the June 8, 1976 ballot.

However, the presence of Proposition 15 on the ballot for consideration by the voters resulted in the passage of three laws by the State Legislature which accomplished at least some of the goals of the Initiative. The previous massive commitment to nuclear energy was slowed with the result that greater interest was shown in alternative energy resource development. It was my privilege to be involved in the study on evaluation of the Social, Economic, and Environmental Impacts of Proposition 15 prepared for the Federal Energy Administration during the spring of 1976.

Coal Utilization

The California State Government has taken the real national leadership role in the development of advanced geothermal and solar energy development under the administration of Governor Edmund G. "Jerry" Brown, Jr. This leadership has been manifested through the auspices of the California Energy Resources Conservation and Development Commission under the direction of its Chairman, Mr. Richard Maullin. It has been recognized that extensive energy conservation can reduce immediate future demand for the progressively depleted domestic oil and gas resources to minimize short-term shortages. It is also recognized that solar energy provides a potential long-term solution to the overall national problem, particularly in California and other Western states.

The real problem that needs to be addressed regarding coal utilization is the intermediate term period between 1985 and 2000, and perhaps beyond until 2025. Coal has been playing at least a minimal indirect role in the California energy picture since 1964 with the startup of the Four Corners power plant in Farmington, New Mexico in 1964. This plant now produces about 2,050 megawatts, where about 60 percent is transmitted to California. There are presently 4 coal-fired power plants located in Arizona, New Mexico, Nevada, and Washington, which provide at least 2,400 megawatts of electricity for California. These plants were initially built outside the state largely to avoid its stringent air pollution requirements, and to be adjacent to fuel supplies.

There has been increasing recognition that it may not be desirable as a long-term policy to cause its coal utilization facilities to be built outside of California to get around the state's stringent air quality restrictions. Possible reasons for locating at least some coal combustion and conversion facilities inside California include the following: 1) the proximity to demand centers; 2) the security of having energy facilities regulated by the state government itself instead of another and potentially hostile state; 3) the state obtains the direct and indirect benefit of the increased economic taxation and employment base; 4) the state is then less subject to the threat of economic blackmail of electricity or synthetic fuel rate increases in retaliation for so-called pollution problem exportation. The problem of in-state versus out-of-state location of coal-based energy facilities occurs because of the fact that California has only very small indigenous coal reserves of less than 100 million tons, which are not easily mineable.

The first industrial coal-fired combustion unit located inside California started up in late 1976 at the Kerr-McGee Corporation chemical plant near Searles Lake using Utah coal. This facility has an electricity equivalent steam generation capacity of about 200 megawatts and uses an estimated 600,000 tons of coal per year. Pacific Gas and Electric Company is planning to build the 1,600-megawatt, coal-fired Montezuma power plant at the headwaters of San Francisco Bay near Collinsville, which would use about 5.1 million tons of coal per year.

Southern California Edison Company has plans to build a coal-fired power plant near the site of the now-cancelled Sun Desert nuclear plant on the Colorado River near Blythe. This plant would have a generating capacity of 1,000 megawatts and would use about 3.2 million tons of coal per year from either New Mexico or Utah.

Southern California Edison Company is also involved in the state's first coal conversion facility. This plan is a 100-megawatt equivalent combined cycle medium BTU coal gasification plant, which will use about 300,000 tons of coal per year.

TEXAS SITUATION

Energy Usage

Texas is a state like California in that it has been almost entirely reliant on petroleum and natural gas as major energy sources in the past. Like California, Texas has relied almost entirely on natural gas as a utility and industrial boiler fuel in the past, and also as a petrochemical feedstock for ethylene production. Unlike California as the nation's largest net energy-consuming state, Texas is the nation's largest net energy-producing state at the present time.

It is not widely known that Texas may become a net energy-importing state as early as 1987. This change will occur because of the continued trends towards increased oil importation from the Middle East, the possibility of importing natural gas from Mexico and Algeria, the possible future large-scale importation of Western coal for electric power generation, and the continuing trends towards decreasing in-state oil and gas production. A large-scale unregulated intrastate natural gas market has developed in Texas where sufficient price incentives have resulted in increased in-state natural gas drilling to provide supplies for the state's industries.

As a result, most new natural gas production has gone into the unregulated intrastate market to the exclusion of the federally regulated interstate market. Texas industries now have sufficient energy supplies to fuel the state's booming economy but Texas consumers now pay among the nation's highest utility bills. Texas has strongly resisted attempts by other states in the past to divert its indigenous natural gas supplies from the unregulated intrastate market to the regulated interstate market.

The desire of the State of Texas to provide energy for its large-scale petroleum, petrochemical, chemical, and metallurgical industries has placed it in direct conflict with the interests of the State of California. California has unsuccessfully attempted to divert natural gas supplies to industrial and utility boilers to help alleviate the state's serious air pollution problems. The possibility of successful diversion of natural gas by California away from Texas would also act to aggravate the already serious air pollution problems in the Houston-Galveston metropolitan area. The result

would be merely to transfer the air pollution problem from Los Angeles to Houston by gas diversion.

Coal Conversion

In recognition of the fact that the state's oil and gas resources were finite and decreasing in magnitude, the Texas Railroad Commission issued Docket No. 600 in December of 1975. Docket No. 600 required existing industrial and utility boilers to reduce their net natural gas consumption by 10 percent in 1981 and by 25 percent in 1985. This ruling also prevented tie-ins of natural gas on new boilers without specific permission of the Commission, which would be granted only under the most extenuating circumstances.

The result of implementation of Docket No. 600 has been a major shift of the state's electric utilities from natural gas to either Western subbituminous coal or Texas lignite coal. In 1971, over 95 percent of the state's electricity was generated by natural gas with only 1 percent by low-grade lignite coal. By 1977, 81 percent of the state's electricity was generated by natural gas with 14 percent by either subbituminous or lignite coal (no nuclear). It is estimated that by 1985, 60 percent of the state's electricity will be generated by Western subbituminous or Texas lignite coal, only 25 percent by natural gas, and 8 percent by nuclear power.

A major program of construction of power plants fired by Western subbituminous or Texas lignite coal is in effect at the present time. There are presently 4 Texas lignite coal-fired power plants in operation in Texas with a combined generating capacity of 3,410 megawatts. There are also 4 Western coal-fired power plants in operation in Texas with a combined generating capacity of 2,744 megawatts. By 1985, it is expected that there will be 13 lignite coal-fired power plants in operation or under construction in Texas with a combined generating capacity of 18,515 megawatts, and 12 Western coal-fired plants with a combined generating capacity of 10,943 megawatts. It should be emphasized that the electric utility industry in Texas has selected to go with primary use of coal and lignite for electric power generation instead of nuclear power, although there is little organized opposition. This decision was made primarily for economic reasons.

The proposed coal conversion program will result in a total use of 58-million tons per year of Texas lignite coal and 40-million tons per year of Western subbituminous coal by 1985 in the utility sector. Additional coal conversions are taking place in the industrial sector, primarily in the cement, lime, paper, brick, petrochemical, and chemical industries. The conversions will require between 13- and 24-million tons per year of Western coal use, and from 1- to 6-million tons per year of lignite by 1985. A 1,000-megawatt equivalent cogeneration plant burning Eastern coal in Texas City serving 3 industries is one of the projects planned.

In addition, it is projected that there will be about 5-million tons of Texas lignite used per year for aboveground coal gasification, underground in situ gasification, and coal liquefaction at 3 different plants. Something less than 1 million tons per year of Eastern coal will be used for coal conversion by 1985. The result of all of the ab-

coal uses in Texas means that there will be a consumption of about 66-million tons per year of Texas lignite coal by 1985, about 64-million tons per year of Western subbituminous coal, and about 3-million tons per year of Eastern coal, or about 130 million tons per year in totality. This total coal consumption is projected to increase to as much as 200 million tons per year by 2000, or about 30 percent of the present national production.

ENVIRONMENTAL IMPACTS

Texas Usage

The proposed coal conversion program in Texas will act to produce substantial increases in air pollutant emissions. Particulate matter emissions in Texas by 1985 are projected to increase by 92,800 tons per year, or 7 percent of the 1973 state total of 1,406,132 tons per year. Nitrogen oxide emissions are projected to increase by 671,600 tons per year by 1985, or 32 percent of the 1973 state total of 2,111,113 tons per year.

Based on the previous fuel consumption data, the projected increases in sulfur oxides emissions from the proposed coal conversion with the uniform requirement of Best Available Control Technology are 170,810 tons per year by 1985. These emissions represent an increase of 14 percent above the 1973 state total of 1,214,910 tons per year. The comparable sulfur oxide emission increase is 1,708,100 tons per year if no controls are employed, representing an increase of 140 percent.

The uniform requirement of Best Available Control Technology for sulfur oxide control on all new utility and industrial coal-fired boilers will act to accelerate the shift to Texas lignite from low-sulfur Western coal because of the lower transportation costs. This BACT requirement as now proposed would require a uniform reduction in sulfur oxide emissions of 80 to 90 percent on all coal-fired power plants irrespective of fuel sulfur content. The result of the BACT regulations would be to favor the use of the adjacent higher sulfur content Texas lignites in Texas and Eastern coals in the East and Midwest at the expense of Western coal. Consequently, more low-sulfur Western coal would probably then be available for use at a lower price by California for industrial and utility applications, which would also make coal more competitive with alternative energy sources.

California Usage

The major increased use of coal for California would result in increased air pollutant emissions, where the degree of increase would depend on the rate of growth and the fuel mix. With a major commitment to increased coal use, net coal consumption in the electric utility sector could increase from the 10-million ton per year level in 1977 to as much as 20- to 25-million tons per year by 1995, and as much as 70- to 220-million tons per year by 2000.

It would probably be difficult to use much coal in the industrial sector in California by direct combustion because most industrial plants are in regions with existing air quality problems along the Pacific coast or in the Central Valley. However,

the coal could be converted to synthetic gaseous fuels outside of metropolitan areas, then piped to existing industries, buildings, homes, and utilities in urban areas to alleviate air quality problems. Coal gasification could use as little as 10-million tons per year by 1995 or as much as 150-million tons per year with complete conversion of existing uses.

Coal liquefaction to methanol or synthetic oil would act to reduce the air pollution problems in urban areas from motor vehicles as well as reduce reliance on imported petroleum. It may well be preferable to locate many of these coal conversion plants inside California in areas where sufficient water may be available to maximize economic benefits and minimize economic hazards. Candidate sites for coal conversion include some coastal locations, the Northeast Bay-Delta area, the Sacramento Valley, and the Colorado River. The air pollutant emissions from these facilities can generally be more easily contained than from conventional coal-fired power plants where it may be desirable to utilize common siting of coal conversion and coal-fired power plants to maximize the potential for waste by-product utilization.

Siting Potential

A major commitment to greater coal utilization for California would involve an increased commitment to determine potential candidate sites within the state, as well as outside the state. The proportion of this increase, which would occur in the state as compared to outside the state, depends on the enforcement and interpretation of existing and proposed federal and state regulations. It is estimated that as much as 3,000 megawatts of coal-fired generating capacity could be readily sited in California by 1985, and 16,000 megawatts by 1995.

By major changes in state policies and regulations, the equivalent of as much as 50,000 megawatts of coal-fired generating capacity could be constructed in California by the year 2000, which is approximately 75 percent of the total requirement under the most optimistic increased coal-use scenario. This potential in-state siting is limited to approximately the same extent by air quality constraints and by cooling water availability. The coal-fired generating capacity requirements for California could range from 9,000 to 14,000 megawatts by 1985, of which as much as 21 percent could be readily located within the state. By 1995, total maximum coal-fired generating capacity requirements could range from 18,000 to 69,000 megawatts, of which up to 23 percent could be readily built within the state. The potential siting capability of coal-fired power plants in California is broken down as follows: 1) North Bay - 3,000 MW(e); 2) Sacramento Valley - 12,000 MW(e); 3) Northeast Plateau - 10,000 MW(e); 4) Mohave Desert - 10,000 MW(e); 5) Colorado Desert - 15,000 MW(e).

Air Pollution

The major commitment to increased coal use for California would result in increased air pollutant emissions. The particulate emissions in the state are projected to increase by as much as 96,600 tons per year by 1995, or 14 percent of the present state total of 711,750 tons per year.

Major coal use for California would increase the state total sulfur oxide emissions of 470,850 tons per year by 354,000 tons per year by 1995, or 75 percent, with 70 percent controls. If flue gas scrubbing were not used, the greater sulfur oxide emissions would increase the state total by 2,473,000 tons per year, or 525 percent.

Perhaps the most serious potential air pollution problem in California lies with nitrogen oxides. A major commitment to coal would increase the state's nitrogen oxide emission total of 1,327,000 tons per year by 1,637,000 tons per year, or 125 percent. This problem would have its greatest significance in the Sacramento Valley, where the relatively elevated nitrogen oxide levels occur primarily as the result of vehicle emissions in the Sacramento area, along with the relative lack of major nitrogen oxide-consuming industrial hydrocarbon sources.

It is going to be necessary to develop better emission control technologies for air pollutants from coal combustion. The implementation of the present sulfur oxide and particulate controls on the maximum projected level of 69,000 megawatts of coal-fired power plant capacity would result in an additional capital cost of 5-billion dollars by 1995 with annual operating costs of about 2-billion dollars. No satisfactory systems are presently available on a commercial scale for control of nitrogen oxide emissions from coal-fired power plants. Trace metal, organic, and radioisotope emissions must also be controlled from coal combustion and conversion.

Solid Wastes

The recovery of usable by-products from air pollution control systems employed on coal-fired power plants is desirable to maximize economic returns and to minimize solid waste problems. Fly ash and bottom ash could be recovered for resale and reuse as cement aggregate, where as much as 21-million tons per year could be generated by 1995. The extensive use of throwaway flue gas desulfurization would increase the amount of sludge generated by as much as 41-million tons per year by 1995. The maximum projection of 62-million tons of solid wastes generated from coal use is greater than the total municipal solid waste generation of all cities and towns in California.

The use of regenerative flue gas desulfurization systems on future coal-fired power plants would enable up to 20-million tons per year of elemental sulfur to be produced at the maximum coal use rate by 1995. This material could be used to neutralize alkaline soil in the Southern San Joaquin Valley or along the Colorado River or Imperial Valley to enhance agricultural productivity. It is desirable to develop a system to produce nitrate fertilizers from the nitrogen oxides emitted from coal combustion, where these materials can command more premium values than sulfate-based fertilizers.

An additional advantage of locating coal-fired power plants in California is that it would then be possible to fire municipal and agricultural solid wastes in combination with coal. The municipal wastes could be generated in the urban areas of the state and hauled by rail to power plants located in

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the Southeast Desert or the Sacramento Valley and then burned with coal for energy production. The agricultural or forestry solid wastes such as rice stubble or cotton bolls or waste wood generated in the Central Valley could be hauled to power plants for combustion in combination with coal. The combination firing of coal with solid wastes would act to reduce the sulfur oxides and nitrogen oxides emissions from the power plants. This combination coal-solid waste option would not be as viable for coal-fired power plants located outside of California because of the greater net transportation costs to and lower population densities in neighboring states.

Water Resources

The major commitment to increased coal use for California would result in significant water consumption impacts. The siting of coal-fired plants in California and adjacent states would normally be done in areas where coastal cooling is not an option to minimize adverse air quality problems. Maximum coal use by 1995 would entail a total consumptive use of about 950,000 acre feet of water per year. This use represents about 3 percent of the state's total runoff, but between 50 and 300 percent of that considered available for energy production. Approximately 15 percent of this consumptive use results from air pollution controls with the remainder largely for waste-heat dissipation.

Water resource availability represents a real constraint on future coal use for California. The State of Utah has established a water use policy amenable to coal energy development for California. Large underground water deposits in Nevada may make future power plant siting for California feasible in terms of cooling water requirements, or alternatively used to supply water for coal slurry pipelines. However, Arizona and New Mexico have established more stringent policies regarding water use for energy production, which are at least partially motivated by conflicts with Indian tribes over water rights questions within their states.

Major potential conflicts may result between competing water resource needs between energy production and agriculture in attempting to provide future coal use for California. Major coal-based energy development in the states of the Colorado River Basin outside of California will result in diversion of agricultural waters in Arizona, Southeastern California along the Colorado River and in the Imperial Valley, and with Mexico in the Mexicali Valley. Interstate compact and international treaty water rights questions may well be involved.

This water diversion for coal energy production outside California would result in reduced water quantity availability along with poorer water quality in terms of greater concentrations of dissolved solids. The major use of in-state coal-based energy development would act to reduce these adverse impacts on agricultural water usage in the Rocky Mountain states unless slurry pipelines were employed. The result would be to transfer the water problem to the agriculture in the Sacramento Valley. Coal-fired power plant development will act to require some water diversion from existing agricultural uses. The extent of this diversion can be minimized by encouraging

the extensive use of brackish ground, irrigation, and municipal wastewaters wherever feasible as power plant makeup waters, especially in the Sacramento Valley and in the Southeast Desert.

CONCLUSIONS

Coal will play an increasing role in California's energy future between 1980 and 2025 as oil and gas become increasingly depleted, but before solar energy becomes the predominant future supply source. A major commitment to coal use for California could necessitate the use of as much as 70 to 220 million tons per year for electric power generation alone by 1995, depending on fuel mix and demand growth rate. The total potential coal consumption could be as much as 100 to 120 million tons per year if a modest program of synthetic fuels usage is projected for industrial gas usage and methanol production for transportation by 1995.

The location of coal-based energy production inside California will act to reduce the state's economic vulnerability to arbitrary electricity or gas rate increases from other states enacted as possible retaliation for pollution exportation. The state would not be protected from fuel price increases from potential suppliers, from arbitrary fuel severance tax increases, or from unreasonable coal transport rate increases. The location of coal-based energy inside California would also act to increase the state's tax and employment base.

The extensive use of coal-powered electrified transportation for intercity railroads and intracity electric vehicles would act to substantially improve air quality in the South Coast Air Basin as well as electric utility load factors with possible cost savings to consumers. Its use would transfer the emissions to more easily controlled single stationary point sources located outside of the Basin instead of from cars in the Basin. The gasification of coal with piping to existing industrial boilers could save on industrial plant capital investment and also alleviate the adverse consequences of direct coal combustion in populated urban areas. The coal energy could be transported from plants located outside the affected urban areas by direct transmission of electricity, by conversion to a synthetic liquid or gaseous fuel, by haulage by electrified railroad, or by a slurry pipeline.

Increased coal use for California will involve air pollution impacts on both itself and the surrounding states. The location of coal-based energy facilities outside the state will minimize the air quality impacts on California because of their downwind location. However, the location of these facilities in other states may involve added siting constraints because of proximity to national parks, siting in complex terrain, and objections from environmental groups regarding visibility and other effects. The major location of coal-fired power plants inside California will act to aggravate the nitrogen oxide problem in the Sacramento Valley and the suspended particulate problem in the Southeast Desert. Emission offsets may be needed in the former case and allowance for natural background dust in the latter case.

The uniform application of sulfur oxide scrubbing will be necessary on coal-fired power plants located in California as well as high efficiency particulate controls. There is a definite need to develop emission control technologies for nitrogen oxides on coal-fired power plants to be sited in the Sacramento Valley. The development of emission control systems should be encouraged that produce usable agricultural fertilizers such as sulfates and nitrates. These nutrients would have special applicability in the often sulfur- and nitrogen-deficient California soils, especially in the San Joaquin Valley. Policies may need to be developed to encourage the development and utilization of by-products recovered from the emission products of coal combustion and conversion. Policies should also be developed to stimulate the combination firing of coal and solid wastes at power plants, such as rice stubble and municipal refuse.

Increased coal use for California will probably involve diversion of waters from agriculture, especially during dry periods. This diversion will probably be necessary either in the Colorado River Basin with primary out-of-state coal use, or in the Sacramento Valley with major in-state coal use. The regulatory conflicts with other states and Mexico involving water use can be reduced with primary in-state siting of coal-based energy facilities and through the extensive use of agricultural and municipal wastewaters as sources for

cooling water makeup. Slurry pipelines might also be used for coal transport to California, although they involve substantial water use impacts for the relatively arid Rocky Mountain states supplying the fuel.

Increased coal use for California will be necessary in the next 20 to 45 years to fill the gap between declining oil and gas use and solar energy. The siting of 16,000 to 50,000 megawatts (or 23 to 75 percent of the maximum estimated need) of equivalent coal-based generating capacity in California is feasible in terms of cooling water availability and air quality regulations judiciously applied.

The development and implementation of effective yet reasonable environmental regulations will be necessary to facilitate future coal use in California without unduly adverse environmental impacts. Primary emphasis needs to be placed on the rapid development and use of suitable environmental control technologies to mitigate the potential adverse consequences of coal combustion and conversion as an alternative to limiting fuel supply options. A possible side benefit of development of the advanced emission control technologies for sulfur, nitrogen, and particulate materials is the capability of reducing emissions of the potentially more hazardous trace metals, organics, and radioisotopes from coal utilization. The housing of a major environmental control technology industry involving coal utilization in California may also have significant economic benefits to the state.

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REPORTS OF NONPROFIT ORGANIZATIONS

(These reports are comments on the Conference submitted by interest groups and reproduced here as facsimile.)

CONFERENCE ON COAL USE FOR CALIFORNIA

May 9-11, 1978

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**Reports of non-profit organizations sponsored by the
California Energy Commission to attend and participate
in the Coal Conference pursuant to Contract Amendment
500-091 (7/8) am. 1**

**CAROLYN L. KEMMLER
Public Adviser
California Energy Commission
1111 Howe Avenue
Sacramento, California 95825
(916) 322-3477 / (800) 852-7516**

LIST OF ORGANIZATIONS RECEIVING CONTRACT AWARDS

<u>Organization *</u>	<u>Conference Attendee</u>
CITIZENS FOR A BETTER ENVIRONMENT James Cannon 88 First Street, Suite 600 San Francisco, California 94105	James Cannon Dr. Wayne T. Williams
THE BLACK BUSINESSMEN'S ASSOCIATION OF LOS ANGELES Clarence B. Lofton 3840 Crenshaw Boulevard, Suite 202 Los Angeles, California 90008	Clarence B. Lofton
LEAGUE OF WOMEN VOTERS OF CALIFORNIA 942 Market Street, Suite 505 San Francisco, California 94102	Judy Ortung Phyllis Price
AMERICANS FOR ENERGY INDEPENDENCE Roger N. Moore 1052 West Sixth Street, Suite 334 Los Angeles, California 90017	Robert Kettner
AMERICAN ASSOCIATION OF UNIVERSITY WOMEN Rebecca H. Sparling 2282 - C Via Mariposa West Laguna Hills, California 92653	Caroline Panches
FRIENDS OF THE EARTH Ron Rudolph 124 Spear Street San Francisco, California 94105	Ron Rudolph
NATURAL RESOURCES DEFENSE COUNCIL, INC. Laura King 2345 Yale Street Palo Alto, California 94306	Laura King Wayne Hoffman
ASSOCIATION OF BAY AREA GOVERNMENTS Revan A. F. Tranter, Executive Director Hotel Claremont Berkeley, California 94705	Dr. Ronald Y. Wada Energy Program Manager
PEOPLE FOR AN ENERGY POLICY H. W. Summers Post Office Box 1420 Los Gatos, California 95030	H. W. Summers

Organization

Attendee

CALIFORNIA CITIZEN ACTION GROUP
Roy Alper
909 12th Street
Sacramento, California 95814

John Geesman

ENVIRONMENTAL IMPROVEMENT AGENCY
Sara Hoffman
1111 East Mill Street, Building 1
San Bernardino, California 92415

Sara Hoffman
Energy Coordinator

SIERRA CLUB
Michael R. Eaton
1107 Ninth Street
Forum Building, Room 405
Sacramento, California 95814

Rich Sextro
Ike Eastvold
Dwight Carey
Willie Hyman

* The following non-profit entities submitted proposals which were accepted but were either subsequently unable to attend the conference or to complete and forward a report:

American Lung Association
California Municipal Utilities Association
Redwood Empire Division of the League of California Cities.

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COAL USE IN CALIFORNIA

**comments submitted by James Cannon
to the California Energy Commission
concerning the Coal Conference held
in Pasadena, California, May 9-11.**

**James Cannon is Research Director of
Citizens for a Better Environment,
88 First St. San Francisco, Ca. 94105**

The three-day Conference on Coal Use in California, co-sponsored by the California Energy Commission and the U.S. Department of Energy and held in Pasadena, May 9 through May 11, was certainly a significant event if for no other reason than the fact that it was the first major conference on the subject ever to be held within California's borders. It marked an important step in establishing lines of communication between people with different backgrounds and perspectives -- including government officials, energy developers and consumers, and environmentalists. The diversity of opinion expressed at the Conference concerning the proper role of coal in California's energy future certainly points out that coal use will be a very controversial topic here. The transcript of the presentations made at the Conference will provide the State with a valuable catalogue of this diversity of opinion.

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While Citizens for a Better Environment feels that the Coal Conference provided a significant interchange of information and while we were pleased to be able to attend, it is our belief that the Conference failed to identify and examine several critical issues concerning coal use in California. Nearly all the sessions involved generalized discussions of technical aspects of coal utilization -- e.g., the development status of advanced coal conversion technologies, the capability of railroads or slurry pipelines to transport coal, and the efficiency of air pollution control equipment to reduce harmful emissions from coal burning power plants. This information, though interesting, is generally available from a wide range of sources, including scientific literature, trade magazines, and government and private industry funded studies. As someone reasonably well-versed with state-of-the-art coal utilization technology -- and I believe most people in the audience had at least my level of background -- I did not find myself particularly enriched by the short, superficial discussions at the Conference.

It seems to me that there was an unnecessary compartmentalization of subject matter at the Conference which hindered the development of insightful debate on coal issues. Take, for example, the session on coal transport -- which, by the way, I found to be among the most interesting. A representative from the Bituminous Research Inc. told us there was plenty of coal in the West; a representative from Southern Pacific railroad said that trains can transport coal to California; and

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a representative from ETSI promised that coal slurry pipelines could be built to move coal into the State. As I said, I enjoyed the session, but mainly for the glibness of the speakers. When I reviewed my notes afterwards, I found very little to write down that I didn't know when I walked into the Conference.

The essential questions which should have been the focus of the Pasadena Conference are: What should California do about coal? Do we need it? How much do we need? How should we use it? Where should we use it? Where should we get it from? How should we get it to California? What are the environmental impacts from coal development? Are we cutting off more viable long term energy options by going coal? Some speakers attempted to address these questions, but most merely added to the list of options available for California.

The Conference generally failed to address the public policy issues involved in coal use. It resembled in many ways industry trade shows dominated by salesmen extolling the virtues of their products or schemes. To me the most valuable part of the Conference turned out to be the first hour of the first day when we were addressed by Jerry Brown and Richard Maullin. These two speakers each addressed policy questions more directly than anyone else and provided some concrete information of interest to the constituents of the Citizens for a Better Environment. Jerry Brown's statement that "our official policy is one of encouragement of coal" followed by Maullin's pledge to "remove the ominous and increase

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the relevance of coal" contain more relevant new information than all the technical slides of the Texaco spokesman explaining the Company's low BTU gasifier.

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This is not to say that some other issues were not competently discussed by other speakers. For example, Jack Moore of Southern California Edison explained in precise terms his company's plans to utilize coal over the next several decades and the reasons for those plans. Joseph Oxley succinctly discussed the potentially huge market for coal in California's industrial sector. Orson Anderson of UCLA vividly translated Brown's statement encouraging coal developers into new strip mines in the West, tonnages of coal which must be extracted, miles of new track which must be laid, volumes of water needed for coal conversion, strings of unit trains, and dollars in capital investment. Finally, the presentations by representatives from each of the major coal producing states at the Wednesday morning session provided some very interesting insights into the attitudes of the citizens and governments of the areas to which California must turn for coal.

A major reason why the coverage of most topics was inadequate or non-existent was that the overall balance of the Conference reflected a heavy emphasis on corporate and governmental interests, with the near exclusion of the "public interest" sector. With the exception of the Sierra Club's Mike Eaton, all the people most conversant and knowledgeable of public concerns about coal development in California were in the

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audience and not on the speakers platform. Hence, it came as no surprise that the major issues concerning the public's acceptability or rejection of coal use in California were scarcely mentioned during the three days, except, of course, during the numerous, and very stimulating, coffee break dialogues.

Public Acceptance of Coal is Vital

CBE believes that the public's reactions to coal use in California will be pivotal in determining the rate, type and location of coal development within the State. Californians treasure -- perhaps more so than citizens of any other state -- the values of a clean, healthy environment. They recognize coal as an inherently dirty fuel, whose use has devastating environmental repercussions from the moment it is extracted from the ground until particles of soot and dust escape from a power plant smoke stack. They also recognize that coal use for California involves complex technology, will cost billions of dollars, will produce new massive, centralized power plants, thousands of miles of rail beds and electrical transmission lines, and will consume huge volumes of scarce water supplies. They are apprehensive that the advent of coal to California can only degrade the quality of California life. Their apprehension borders on fear when they realize that control over coal technology will likely rest in the hands of the few powerful utility companies.

Certainly not all Californians share these concerns about coal use. But CBE, which gains 80% of its funding from a door-to-door canvass

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of Bay Area residents, has discovered widespread interest and extensive confusion concerning coal issues. In response to enquiries from our constituents and as a result of our research program, CBE is developing a policy concerning coal utilization in California. Though only in its formative stage, there are several coal related issues about which we have strong concerns. The remainder of this report will discuss these concerns, with particular reference to the 1600-megawatt power plant proposed by Pacific Gas & Electric for the Central Valley.

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Off-Site Environmental Impacts

An incredible amount of coal -- which will probably be mined in Utah, Arizona, and New Mexico -- will be consumed in California if large scale coal development takes place here. Orson Anderson, in his presentation before the Coal Conference, calculated that about one hundred million tons of coal could move into California each year. This would require either 15-20 new underground coal mines or 10-12 new strip mines in the West. We perceive that massive environmental devastation of the land surface of strip mines providing coal to California is inevitable, even if strict reclamation practices are followed. Irreplacable wilderness areas will be destroyed and the air quality in some of the most pristine regions of the country will be impaired. Underground mining, though environmentally preferable to strip mining, is extremely dangerous and presents occupational health problems to miners employed there.

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In addition to these direct environmental health and safety consequences from coal mining, a massive upsurge in coal mining in the sparsely populated western states could have devastating social, economic, and political repercussions there. Studies on boom towns invariably correlate large population jumps in small towns with increased crime, alcoholism and other social problems. We have been impressed by the widespread concern among people contacted by our canvassers about the environmental consequences in coal mining regions.

Reliability

A second major concern voiced by our constituency relates to the reliability of coal supply for large power plants and the reliability of the power plants themselves in delivering electricity to residential users. The proposed PG&E plant, for example, would require two unit trains -- each 78 cars long -- of coal a day to keep its furnaces going. This coal must be transported by one of two financially troubled railroads approximately 1,000 miles over one of the largest mountain ranges in the country without interruption for 35 years. Furthermore, much of the coal lies under land presently owned by the federal government, a western state government, an Indian tribe, as well as private coal developers, farmers, ranchers, and land speculators. The availability of large amounts of coal at reasonable cost through various leasing arrangements with the owners of this land seems to me to be a difficult promise to make.

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In terms of the reliability of energy delivered from, rather than to, the power plant, many of our constituents have expressed concern about delays in construction and licensing of large power plants in the State. Furthermore, the threat of disruption due to equipment failure, sabotage, or other difficulties seems larger for large centralized power sources than the risks for decentralized systems. With this in mind, many people we have contacted are more in favor of decentralized coal plants, using "clean" coal conversion technologies such as gasification, liquefaction, or fluidized bed technologies. But these technologies also run a large risk of unreliable performance because they are new and have a brief commercial history.

Will Food Prices Rise?

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In addition to these concerns about "off-site" impacts of coal utilization, we are deeply concerned about the environmental repercussions of coal burning on the communities where power stations are located. The California Air Resources Board presented substantial documentation at the Conference that proposed large coal burning power plants in California will meet federal ambient air quality standards. We do not have the data to dispute these assessments, but we still fear adverse impacts of the air pollution from coal burning. Federal ambient air standards were set at levels deemed necessary to protect human health, but they are not designed to protect agricultural crops from ravishment from air pollution. Preliminary findings of a research project underway at CBE indicate that the potential effect of sulfur

Assessment

dioxide air pollution from a coal burning power plant in the Central Valley could result in millions of dollars worth of crop losses. And SO_2 is just one pollutant in a vast array of toxic substances which are inevitably emitted from coal burning power plants. Many of these pollutants have been shown to act in concert, with a combined environmental impact on crops that is larger than the sum of the impacts of each pollutant acting alone. The effect on food availability, quality, and price from extensive coal burning in the central part of the State is probably the major concern voiced to us by Bay Area residents.

Public Health

Another major air pollution issue concerns the protection of human health. Even if sulfur dioxide levels from coal combustion meet federal standards, its ability to act in combination with oxidants and particulates could still cause substantial health problems to large segments of the Central Valley population, especially among the young, the very old, and the infirm.

Social Problems

There are other potential adverse impacts from large coal burning power plants in the Sacramento Valley. CBE fears the potential disruptive influence of the influx of hundreds of construction and operating personnel for each proposed rural plant site region. This population influx could disrupt existing economies and lifestyles and even result in a net job loss due to reduced crop yields in the area.

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An influx of new workers could temporarily strain available housing near power plant sites -- causing the erection of shabby inadequate temporary housing. Ultimately, however, the demand for housing by construction workers will bottom out upon plant completion. Homes built in response to this temporary demand will become a glut on the market and real estate depressions could occur when construction crews leave power plant construction areas. Furthermore, land values in areas surrounding a coal fired power plant could drop substantially because of increased air pollution and because areas surrounding large power plants are substantially less attractive for recreational activities and resort and retirement communities.

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Water Issues

Another question troubling CBE is the effect of centralized power plants in central California on water sheds and water quality. A large power plant consumes approximately 20,000 acre feet of water per year. This could significantly threaten water use patterns in the Sacramento Valley. Furthermore, air pollution from coal burning could stress dominant tree species in the water shed regions of the Sierra Nevadas, further reducing available water supplies.

Energy Demand and Appropriateness of Coal

There are a final set of issues concerning coal development in California which have aroused considerable concern among our constituency. These include broad generic questions of whether we need new electrical

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generating plants and if there are other paths besides burning coal we could take to fulfill future energy demand. These generic questions reflect, we feel, a concern about the appropriateness of direct-fired, large, centralized, coal burning power plants as part of the State's energy program for the future. California is virtually unique in this country in that it has survived to date quite handsomely without coal. It is also the place where many new innovative energy philosophies have germinated. Many of these philosophies call for the replacement of large conventional power plants with a combination of energy conservation programs and energy generation via "alternative" technologies using solar, biomass, tidal, and geothermal energy resources.

In the face of these new exciting energy possibilities, the State's major utilities have clung steadfastly to their historical projections of expanding energy demand and continue to push conventional energy technologies rather than alternative systems. We believe there is considerable concern that these projections might reflect the inability of a conservative industry to change more than real energy needs. Our constituency asks to be convinced that additional supplies of electricity are needed in the future. If that can be established, it expects to be convinced that conventional power plants -- including those that burn coal -- represent the most acceptable pathway to meeting this demand, in an economic, environmental, social, and political sense.

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CBE's Position

CBE's policy vis-a-vis coal, at this point, is guided by a general perspective which says that large centralized coal burning power plants represent the use of an inappropriate technology consuming a limited fuel which is only marginally appropriate under the best of circumstances due to the environmental and economic problems it causes. We have not closed our minds to alternative uses of coal within California which stress decentralized applications of advanced coal conversion technologies; we neither espouse or rebuke them.

We believe that the Energy Commission should increase its role in educating the general public about coal policy issues. Providing funds to representatives of public interest groups to attend the Coal Conference is an important example of how the Energy Commission can help get information to the general population.

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Secondly, we believe the Energy Commission must be more diligent in tapping public opinion concerning the State's coal policy. It should provide funds for public interest groups to represent themselves, not only in the audiences at coal conferences, but on the podia at coal conferences, and in court and hearing rooms throughout the State where coal strategies and projects are being mapped. The price tag for funding several public intervenors on energy issues throughout the State would be just a fraction of the Energy Commission's budget for the Coal Conference in Pasadena.

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Again, I would like to express my gratitude to you for making it possible for me to attend the Pasadena Conference last month. I have harped -- perhaps too stridently -- on some of my negative reactions to the Conference, leaving out its many positive aspects. I learned a lot, I met many stimulating people, and I came back with many new insights to share with CBE and our constituency. Thank you very much!

**Issued To: California Energy Commission
1111 Howe Avenue, MS 31
Sacramento, California 95825**

**Subject: Coal Energy Conference
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**Prepared By: Black Businessmen's Association of
Los Angeles
3840 Crenshaw Boulevard - Suite 202
Los Angeles, California 90008**

**Contact: Clarence B. Lofton
(213) 292-0271**

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Background

The question of viable resources of energy available to meet the future needs of the inhabitants of California is a very perplexing problem with no simple clear-cut answers available.

The energy crisis presents itself as seemingly a race between the United States for domestic independency of world market influence against the present limitations of technological and financial capabilities that preclude that independence.

In discussion of these external world influences, the ultimate recipient of the price of these pricing policies is the consumer. The variables that determine the price this consumer pays are the OPEC nations, present research, technological advances, the allot box and consumer protection all have a hand in determining the price of goods.

Presently the United States is paying oil prices that are still substantially lower than the world market price. The crisis of 1973 represented the type of catastrophe that occurs where ones domestic supply is contingent on external forces. The results that followed from this energy crisis created a recognized need for a drive for energy independence.

The effects of 1973 was of such a magnitude that many small and minority companies went out of business because of an accumulation of problems. The most serious being the lack of access to the means of transportation and an inability to acquire the necessary materials needed for production.

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Presently, the topic of viable energy alternatives is a topic somewhat removed from the scope of minority concern.

The inner city resident usually of a lower economic base also suffers from a lack of exposure to discussions of domestic energy development. The lack of access to these decision making boards that deal with energy alternatives such as coal usage invariably leave this inner city Black constituency without a voice in future energy use planning. The failure to fully translate the technical jargon into meaningful interpretable applications of the inner city consumer leaves him in a position of weakness.

Born out of this utter frustration the Black Businessmen's Association under the leadership of Clarence B. Lofton, President, has launched a drive to bring its membership as well as the inhabitants of South Central Los Angeles area into an educational process in regards to the energy question. This new thrust came about by the recognition that certain external forces to the minority businessmen's market place and more specifically, the minority community often determines the productivity of this area.

The problem of minority businessmen, who often are located within the inner city will undoubtedly be influenced by the determination of what particular source of energy is chosen. As example, the small business person must often act only as distributor and retailer to prior manufactured goods. The elasticity of demand for his product greatly depends on the price and consumer need.

The manufacturer who has the greater access to information relating to future trends and the ability to buy in volume, will be in the best

position to absorb necessary cost increases. Due to lack of access to timely information and the inability for discount buying the minority businessperson will undoubtedly have to pass a larger portion of their cost on to the consumer.

Because of its position within the market place, the manufacturer may very well insulate himself from the immediate consumer and because of product demands, simply be able to engage his products elsewhere without substantially raising his prices.

As a representative of a basically minority and lower income constituency, the BBA is concerned about the lack of translatable language available to the lay person that would indicate the viability of certain alternate energy projects.

Needed are studies and directions that will adequately communicate the price the consumer will pay and the affects this price will have from a socio-economic perspective.

There is very little evidence inner city residents and other minorities are a primary factor in the considerations being given to the policy areas of coal development. This point was highlighted when one of the program directors apologized to the audience for the lack of Indian representation at the conference.

This fact only began to receive serious consideration when it was recognized that much of the land contemplated for potential coal extraction, whether by surface or underground mining will not materialize unless negotiations with Indian nations are successful.

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The above comment is only to emphasize that inner city residents as well as other constituents have to be a prime consideration from the onset in coal policy development.

It is especially necessary for the small minority business vendor to be considered, in future energy resource development.

In other words, it is quite evident that some markets patronized by the small businessman will become obsolete in a number of years because of technological advances, or become economically impractical considering potential limitations on discretionary income of inner city residents due to rising inflation. Again this is an example of intangible socio-economic affects that need scrutinization and review before implementation of energy policies.

Why Conference Held

The future alternative energy sources will encounter entanglements through government, political factors as well as face economic limitations as dictated by technology. The social cost involved must inductively be weighed.

This conference sought to bring together these various interest in coal and share experiences and current developments. The conference was successful at covering the technological aspects of coal development but lagged substantially in areas of social policy and consumer involvement in the decisions surrounding coal.

The conference on coal use for California was an educational and knowledgeable affair. Condensed within this 3-day session was an attempt to address the concerns of viable constituencies whose members offer potential support systems for future development of coal use.

As mentioned in the conference, the United States is at a particular junction in history where substantial changes in its perceptions of the future will immediately challenge life styles and most substantially economic conditions.

Many people tend to conceive coal as being a dirty and unclean substance with more disadvantages than advantages. There are those, when involved in discussions of coal and other alternative energy sources, have vivid pictures of a coal sunk Pennsylvania town.

A Systems Examination of Opportunities of Coal for California

The seminar involving coal use in California explored the potential enormous expenses involved in the building of coal-fire plants. The necessity for this expensive process has to be weighed in light of our domestic need for independence from our present foreign sources of oil.

Several systems of coal delivery producing facilities can be utilized in order to meet the present domestic energy needs. Whether by a Mojave Station-type demonstration site or a coal slurry pipeline, an appropriate means of transportation can be found that will have a least marginal damaging affect on our environment.

In order to fully examine these opportunities for coal it is necessary to assess its commercial practicability. Appropriate and practical capatilization for construction of these sites in conjunction with reasonably projected rate schedules as a result of the construction of these plants have to be considered.

There is also a need to prepare a program to accelerate a study of appropriate technology in these energy fields. Being able to meet certain

cost requirements, for a projected site or coal delivery process is not sufficient without an analysis of the present technological alternatives available.

The necessary variables include economic considerations and capital requirements, the regulatory problems, ramifications of the water usage and availability of transportation of energy to run these coal producing systems.

The recipient of these energy producing systems, the consumer has to also be considered for he ultimately pays for the project. Thus consumer prices should be the other central factor in determining the cost capabilities of productions.

In a discussion of importation of coal generated energy there are two underlying assumptions. Namely that there exist a reasonable foreseeable potential for an oil shortage in the near future. Secondly, that there exist vast reserves that could supply the future domestic needs of our citizens and offset the higher prices that foreign sources could charge.

Yet proponents of increased domestic use find that the system of importation of coal-generated energy runs the significant risk of "high voltage lines." For California to import this energy from power stations outside the state under present technological conditions would impose on the state both benefits as well as disadvantages.

The main disadvantage would lie in that certain states refuse to allow California to set itself up as an exploiter of the natural resources of those neighboring states.

Various states take contrasting positions when it comes to internal development of resources for export to California. Some states seek to

keep conditions constant whereas others thrive for change and economic growth through this potential coal industry.

State Policies

Colorado - Colorado currently finds itself as a supplier of 10% of the nation's coal needs. Mr. Martin Robbins of the Colorado School of Mines argues that Colorado acts as a colony to East Coast users. While continued support to the East is urged, Colorado is also determined to control this exportation with an eye also towards conservation.

Utah - Utah has the largest untapped coal fields in the U. S. One-half of the coal produced remains in the state whereas the other half is exported.

Heavy industry investment is not required because of sufficient government infrastructure. Utah finds itself unwilling to build additional plants to satisfy California needs.

Utah also seeks to control exportation because of the socio-economic affects of increased development on the constituencies of the state.

Arizona - The state of Arizona faces a serious growth rate and more energy will be required to meet its expanding population as well as capital base.

Because of its air, Arizona remains attractive because of it and seeks to preserve it. The state admitted no solutions but only recognized the seriousness of its problem of growth.

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New Mexico - New Mexico is a serious exporter of its energy resources.

The problem that New Mexico faces was its unrealistic pricing policies. The policies were set based on an emphasis that encouraged production rather than conservation.

Wyoming - Wyoming represents a state with a census population count of 332,000. The two largest cities have populations of 40,000 each.

1978 presented the most rapid growth in its mineral producing areas. With the increase in production, the community needs were met for its energy requirements. However, there was considerably high inflation rates due to an increase in community areas that surround production sites.

The state of Wyoming recognizes that laws are needed to protect the health of its environmental community. The state also recognizes the need to help the nation but at the same time recognizes waste by the other states.

The recommendation was that California should use coal in the short-term and arrange for incentives to those consumers who seek to install energy saving methods (i.e., solar income tax credit).

Alaska - The attitude of Alaska was interestingly different in that industrial development was sought to sufficiently create new jobs. Alaska presented a figure of 36% unemployment rate. The present tax base of the city comes from non-renewable sources or seasonal operations. Thus the type of long term production : coal is needed to meet employment as well energy needs. Alaska has a huge supply of coal reserves available for long term extrac . . . The content of this coal is of low sulfur content and high moisture.

The speaker from Alaska pointed to the potential large export market available. Alaska is actively looking for domestic and as well as world markets to supply.

Use of Coal for Non-Electric Uses

Proponents of coal usage for California also point to coals non-electrical uses that are available.

Through coal combustion projects, coal gasification systems exist that can produce useable petroleum. Through advanced technological procedures a non-petro based coal fuel is produced. This synthetic gas can meet the low emissions requirement and prevent the air or water pollution problems common to natural gas. The recognition of the use of coal as a fuel base is clearly a viable immediate source of energy in lieu of nuclear power.

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Future Energy Demands

There is no question of a demand in the future for energy producing methods. The overseer of any present inquisition into coal development viability will hinge on the California Energy Commission. This agency functions as a regulatory agency to ensure appropriate site selection as well as appropriate technology usage.

This agency is also responsible for insuring adequate electric power as well as promoting new technology. The specific concern for electricity forecasting is very important in analysis of coal development.

A central variable that has to be considered is the potential growth of the state. There is a recognition that growth in the state required a parallel energy growth.

Because of this agency's responsibility to promote new technologies, energy intelligence has to be a central focus.

Tremendous growth increase without technological advancement would leave the state in a precarious position. This potential growth should not preclude the satisfaction of the industrial customers need.

The utility company perspective (PG & E) indicated a favoritism for coal use over natural gas. The historic view of coal as dirty and sooty can be changed with advancing technology. Because of the vast potential reserves the utilities feel the need to develop energy resources at rates faster than the population demand increases.

Ultimately the source of development will include input from more than the utility companies. Factors which will influence the final decision are the OPEC influences, current research, the ballot box, and the consumer needs.

Until some type of certainty evolves in this question of energy sources there will be a dampening of chances for investment and the need for encouragement for future energy development.

Environmental Aspects of Coal Use in California

This session dealt specifically with the environmental effects of increased coal use in California.

The public conception of coal is that of a dirty energy fuel source. This reputation clearly emanates from the visions of a coal-dusty Pennsylvania mining town.

In California it is voiced that there is no pure economic coal reserves. To extract existing coal would require a large scale labor intensive project. The ramifications of such a method of production would certainly disturb the socio-economics of the area surrounding the plant sites.

There are several methods of mining coal. Surface mining projects also involve significant land use, irreversible land damage, water, and air pollution and vegetation problems. A second method is that of sub-surface mining. Yet both methods of production environmentalist point to the large percentage of mine product waste (10-20%).

Irreversible land damage is one method in which this waste is of chief concern. For transportation of coal to the Western States, the use of ports would be impractical and uneconomical in view of the position and size of the state. A coal slurry system affords a higher transport cost, however, the water accrued in the coal often makes the coal burn less.

The use of the railroad system for transportation has an advantage in that the coal does not lose its heat, however, the disadvantage lies in the fact that there exist a need for government support to revitalize that mode of infrastructure. It is also necessary for these trains to be supplied with energy.

The feasibility of coal projects lie in the successful ability to deal with the 10-20% of waste created in the surface-mining process. The significant percentage of energy lost through the energy required for transportation and to keep the plant site operational.

The use of water as a constraint in coal production surfaces because of the great need for electricity to run coal production units. Legal constraints exist because of the illegality in unreasonable water diversion. The use of fresh water has serious environmental restraints because of its failure to provide water for agricultural purposes. In areas where the quality of water is unnecessary however the use of saline water could satisfy the water requirements.

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Choices in this energy field require the evaluation of all the variables involved and their short and long term affects.

Economics of Coal

One of the problems of future coal use deals with the economics of its usage. The failure of our states to issue a coal policy statement adds to the inability of interested coal development sources in procuring sufficient capital to encourage coal production. A firm commitment is necessary by the federal government to offer incentives to encourage coal production by way of capital-financing of certain initial projects.

Part of the problem of adequate financing stems from the lack of awareness by the general public. The general public to a great degree has not fully comprehended the seriousness of our general situation. The unfortunate result of this lack of awareness is that the search for new technologies for coal production take time, upwards to fifteen years and more. Yet, new resources must be developed to meet future rising needs.

There is a definite need to educate the consumer about our energy situation and this process must occur in such a manner that the critical message is delivered in layman terms. Without adequate education to reckon with these energy needs the consumer will not be able to fully recognize the full ramifications and needs of available technological options that cure the pollution ills germane to coal-energy productions.

The expense required for pollution control equipment, the actual cost of research and procurement of the coal, its transportation to available markets are the variable fixed cost that will be passed on to the consumer.

An example of the cost when measured against the transportation to California by railway infrastructure showed that for a delivery to Northern California from Wyoming was 910 miles and from Utah 925 miles.

A delivery of coal to Southern California indicated a distance of 925 miles from Utah, 1250 from New Mexico and 1000 miles from Southern California to Wyoming.

Whatever route chosen from whatever state, each location has their own policy in regards to coal development. As mentioned previously, some states take a more conservationist view of their resources.

The environmental impact and socio-economic disturbances in those respective communities carry various cost. This ultimate cost of delivery will be passed on to the consumer.

The variables that have to be considered for a pricing policy are the various transportation cost, pollution equipment requirements, the availability of the coal and on-site requirements.

Some areas tend to vary in their approach as a coal exporting state. While some encourage development, others tend to have a more restricted approach. It is thus necessary that each state policy has to be weighed and translated into actual cost.

Further risk in the future of coal development stem from the uncertainty of return on investment, an uncertain national policy, and the environmental constraints and their degree of enforcement.

Encouragement is needed by the government or the private sector in order for that private sector to have adequate basis for investment.

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Through demonstration projects it was pointed out that early commercial support could be shown by a vitalization of necessary transportation infrastructure and types of guarantees against failure. More specifically, state support could come in the form of demonstration projects, capital grants, investment tax credits, fuel subsidies and product indemnity guarantees. But until we have a district energy bill, incentives for development will lag on the state level as well as the private sector.

The banking perspective looks upon such ventures in terms of long term debt capital requirements. The cost of materials for such a long term venture also have inflationary problems. The financing method employed can only be reasonably estimated because of the variables of new technology and other important vacillating economic variables.

To finance a coal development project it would be necessary to emphasize the venture rather than the balance sheet. It would also be necessary to have a risk-appraisal. This process would evaluate the technical and political environment to decide on the practicality of such ventures. It is also necessary to look at the present technology abilities as well as the environmental practicability of participating in such a venture.

From a practical standpoint, banks will not take on such a risk. However commercial banking enterprises, who are usually more of a medium term lender of 8-10 years would look more favorable on such ventures. However, the question is whether those interested commercial banks can weather the storm of such a large outlay of cash in the light of uncertain national energy policy, inflationary rates and rising environmental constraints

A political analysis as applicable to the economics of coal indicate that anything that will erase the uncertainties will do more to provide money resources than any type of technical development.

Regulatory System **REPRODUCIBILITY OF THE ORIGINAL PAGE IS POOR**

The utility company has to pass the cost of coal development onto the consumer. The cost level required generally arises because of forces external to the projected energy project.

In California it was pointed out that present regulations of the public utilities affords no incentive to find lower cost. A systematic passing on to the consumer of this increase perpetuates itself.

Another factor to be reckoned with is the escalating transportation cost of delivery. Again insufficient government support for the necessary revitalization of support infrastructure is a reason why.

The California Energy Commission has taken the initiative to ensure adequate reasonable pricing as well as providing a more stream line approach to aid these utilities in bureaucracy problems.

In California, several agencies exercise their power according to the strongest political persuasion at the time of decision making. The guidelines of each agency finds a way to inhibit or prohibit certain energy development they oppose.

An example of this is where the California Coastal Commission takes a staunch environmentalist view and calls for 85% of Coastal areas as unsuitable and the other 15% are located on choice reserves and are also unavailable for development.

These regulatory agencies by their various inputs into the bureaucratic decision making process can hinder certain coal developments. These agencies do act however in the interest of the state when their acts correspond to a uniform energy policy void of uncertainty. It was pointed out that an application for a proposed coal site can take up to 6 years. Multiple agency review and alteration simply adds to the cost the utility will have to pass on to the consumer.

Thus a streamline approach is a step in the direction of reform. Design or environmental restraints submerge as necessary variable subject to regulatory agency scrutiny.

There is a need for state as well as federal guidelines to coalesce so as to keep cost of development minimum and allow speedier development to meet those future energy developmental needs.

Of particular interest in this conference was the policy discussion by the environmentalist and industrialist in regards to a National Coal Power Project. The effort of this select body of individuals was to come to a consensus as to the problems, both long and short term in regards to coal usage. The need to differentiate between what are facts and what are value judgements espoused by the environmentalist and industrial positions have to be clarified.

By coming to a consensus position conflict is removed and actual strategy can be established. The consensus view was that no one class of consumer should subsidize another. This fact has far reaching ramifications. This position calls for a balancing of interest so that economically feasible energy sources can be selected. One such view called for the internationalization of social cost.

This was realization of the need to pass on to the consumer the cost of irreversible environmental damage or alteration and to estimate the effects of disturbance of the socio-economic community.

The industrialist position highlighted the need for a federal strategy in regards to surface coal mining. Facts indicated that under present Federal Coal Leasing Program guidelines, lands acquired for coal extraction sometimes were scattered. This scattering of available lands creates increased economic cost because of the need for expanded infrastructure for transportation of the coal.

The utility company pointed to the fact that there is a built in bias in the system of rates charged. This bias tends to offer a lower price to the consumer and fails to fully pass on the cost of seeking new technology to change world influences concerning our energy supplies.

Thus the utilities argue that what is needed are utility rates of expansion that can meet the needs of today's consumer needs and provide for further development by the utility. The utility company as well as industrialist argue that another built in bias with our system is to penalize those ventures into new energy technology that fail.

This cost has to be passed on to the consumer and persuasively restrains the number of ventures because of the risk of failure. The need for some type of federal assistance and support is an idea sought to encourage those companies to seek out new technology and energy sources, and not pass the cost of these ventures onto the consumer.

The consumer on the other hand lacks the knowledge about these developments that utility and industrial persuasion have.

The availability of public forums to educate the consumer was another suggestion forwarded by this group. Equal access to information of new and potential sites and development in technology is also needed.

Even though specifics of proposals were not spelled out, the significance of this group policy meeting was that of resolving conflict and coming to a consensus position in regards to energy source questions.

**REPORT ON CONFERENCE ON COAL USE
FOR CALIFORNIA**

MAY 9-11, 1978

**SUBMITTED BY: PHYLLIS PRICE AND JUDY ORTTUNG
LEAGUE OF WOMEN VOTERS OF CALIFORNIA**

Part I - Reaction to Conference

We would like to begin by applauding the California Energy Commission, the Department of Energy and JPL for sponsoring the conference and initiating a public dialogue on the policy issues facing California with regard to coal utilization. We feel that open discussion of all issues by the various interested parties can lead to early problem resolution. The greatest significance of the conference to California is the attempt by the sponsoring agencies to afford an opportunity for that discussion to begin. However, for a number of reasons discussed below, we view this as only a beginning and want to express the hope that a further, more refined effort be made to extend this dialogue.

The public policy issues surrounding coal utilization in California are many and complex. Overall, we felt the conference planning committee identified the major issues and for the most part were able to organize and arrange the conference in a logical sequence. However, the actual implementation of the conference was somewhat disappointing. The ability and willingness of individual speakers to address the identified critical issues varied

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considerably. A number of problems and issues were evaded by individual speakers, i.e., water supply as a constraint to various coal technologies which may otherwise be quite feasible. This could have been avoided by more careful screening of the speakers invited and/or more explicit direction to the individual speakers. Specifically, each of the speakers discussing alternative technologies should have been asked to address a set of issues including air pollution, cost, energy yield, etc., as well as describing their particular process or technology. Such information on each coal technology would have enabled those representing public interest groups to present to their members an assessment of each coal technology as it relates to other physical and societal factors.

It was most helpful when speakers indicated the assumptions on which they were basing their particular predictions. This sort of presentation more easily lends itself to valid comparisons. Having the assumptions clearly stated and thus easily adjusted if necessary, also facilitates changes of individual predictions without reworking the entire model and allows individual components to be used in specific cases where the entire prediction may not apply. Mr. Edward Griffith's (ARCO) paper on future energy demands in California was an especially good example of this type of presentation.

Although Session II addressed the question of future energy demands in California, a full discussion of alternative scenarios utilizing other energy sources did not occur. California will undoubtedly have an energy mix in the next few decades that will include a variety of sources. The advantages and disadvantages of coal use

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need to be discussed in concert with the prospects for other energy sources. Only by a comparison with other sources can a decision be made as to whether or how much coal will be used in California. The whole issue of whether coal is needed in our mix of energy sources was skirted, and a strong case for coal utilization was not made.

Quite obviously a major attempt was made to involve a balance of interests among the participants and this effort is to be applauded. Notably absent were agricultural interests, representatives of groups such as the Chamber of Commerce, and as mentioned at the conference, Native Americans. The effort to provide a balance of interests on the panels was apparent. In some instances that effort for balance was thwarted by the choice of speakers.

The critical importance of the public's perception of the impacts of coal use was underscored by two of the speakers, Tom Austin and Mike Eaton. This socio-political consideration is certainly one that will need to be explored in greater depth and would be a most appropriate topic for the workshop to be held in the Fall. If there is to be any degree of coal utilization in California it will require public support. The key to enhancing the public perception of coal use will be to involve all parties in the policy dialogue.

Conference organizers are to be commended for allowing time for questions following each panel. In most cases there seemed to be adequate time for those in the audience to address their questions to the speakers. However, the sheer size of the conference and the tendency for the questioning to become quite technical, may have

prevented some in the audience from asking questions of a more social or consumer-oriented nature. It is hoped that the organization of the follow-up workshops will facilitate and encourage this type of questioning.

Part II - League position vis a vis increased coal utilization

The League of Women Voters has just completed a two year study of energy at the national level. Parallel with our national study, the state League identified issues specific to California and asked local Leagues to address those issues as well. Resulting from this two year effort are separate positions -- that of the national League and that of the League in California. Some differences between the two positions exist reflecting our particular concerns here in California. However, for the most part the two positions are consistent. Since all future action by the League will be based on these positions, perhaps it would be helpful to present them in their entirety.

STATEMENT OF POSITION ON ENERGY League of Women Voters of the United States

"The League of Women Voters of the United States believes that the United States cannot and should not sustain its historical rate of energy consumption. Not only as a responsible member of the world community but also in the national interest, the United States must make a significant and progressive reduction in its energy growth rate. To achieve this goal, the nation must develop and implement energy strategies that--while taking account of differences in the needs and resources of states and regions--give precedence to the national good.

Between now and the year 2000, while arriving at long-term energy strategies, the United States should develop and use a mix of energy sources based on the following policies:

- Top priority must be given to conservation; renewable resources, especially solar heating and cooling, bio-conversion and wind; and the environmentally sound use of coal.
- Dependence on imported energy supplies must be reduced.

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- Because finite supplies of domestic oil and natural gas must be conserved, reliance on these sources should not be increased.
- Reliance on nuclear fission (light water reactors) should not be increased. Special attention must be given to solving waste disposal and other health and safety problems associated with this energy source.

Beyond the year 2000, the United States should rely predominantly on renewable resources. To make this change possible, the federal government should:

- give top priority to conservation and to the development and use of solar heating and cooling, solar electricity and bioconversion;
- emphasize energy-efficient technologies, especially cogeneration and district heating;
- support the development of fusion and geothermal energy;
- give extremely low priority to the plutonium breeder reactor.

To achieve a reduced energy growth rate and the optimum mix of sources and technologies, the federal government should:

- use research and development funds, tax incentives and loan guarantees to encourage business, industry and individual consumers to conserve energy and to shift toward the development and use of renewable resources.
- use tax disincentives to promote energy conservation and, in the case of individual consumers, to foster the use of renewable resources.
- gradually deregulate oil and natural gas prices and at the same time tax windfall profits attributable to deregulation.
- set mandatory standards for energy conservation.

Federal standards and compliance timetables that protect the environment should not be relaxed in pursuit of national energy goals.

In developing national energy strategies, the federal government should spread costs and benefits (environmental, social, economic, health) as equitably as possible. In keeping with this criterion, states and regions should take steps to maximize conservation and to utilize their indigenous, renewable resources. There should be assistance for low-income individuals, when changes would bear unduly on the poor.

In the distribution of roles and responsibilities, the following principles should apply:

- The processes used to develop and implement national energy strategies should give a voice to all levels of government.
- The federal government should set national standards to reach policy objectives. States may set more stringent standards, within the context of national policy. Implementation and enforcement of national standards should be primarily at the state level.
- States and regions should cooperate with each other and with the federal government to achieve national energy goals.
- Public understanding and cooperation are essential to the success of any national energy strategy. Citizen participation in decision making must be assured at every governmental level."

STATEMENT OF POSITION ON ENERGY
League of Women Voters of California

"Support of a state energy policy that promotes conservation, fosters the development and use of a variety of renewable energy sources, and considers the impacts of energy development and use on public health and safety and on the environment. State government should provide an efficient, coordinated energy administrative structure and regulatory process and establish state energy policies and minimum standards. Local government should implement state energy policies and standards based on local conditions, with emphasis on conservation.

Objectives:

1. A mix of energy sources to the year 2000 with:
 - a. greater emphasis than now on conservation (using less energy, more efficiently), solar energy (heating and cooling), geothermal power, and other renewable sources, such as bioconversion and resource recovery;
 - b. use of hydroelectric power at its 1977 capacity;
 - c. decreasing reliance on oil and gas.

2. Development and use of energy sources, including the siting of energy facilities, that primarily consider impacts on public health and safety and on the environment. Consideration should also be given to economic factors in evaluation of energy facilities sites.
3. State energy policies and regulatory actions that provide for:
 - a. tax incentives to individual consumers to encourage conservation and use of alternative energy sources;
 - b. state research and development and tax incentives to encourage conservation by business and industry and to encourage development and use of renewable materials by business and industry.
4. Local government measures that promote energy conservation, especially those related to building codes, transportation, resource recovery and public information."

Perhaps most relevant to the purposes of the conference it should be underscored that at the national level the League supports the "environmentally sound use of coal" while here in California League members could not reach consensus on the issue of coal use. Specifically, while some California League members supported increased coal utilization, others expressed concerns about the hazards associated with mining and use of coal. Members were concerned about the need for demonstrated technology to reduce air quality impacts and the need for measures to improve mining safety and to reclaim mined areas.

As to positive impacts -- coal is recognized as an important domestic supply of energy. The negative aspects relate to the environmental health and safety impacts which surround coal utilization. At this point, League members are essentially asking to be convinced that the technology is available to allow coal use without

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sacrificing existing standards.

Recommendations: It is our understanding that this conference is to be followed by a workshop this summer or fall. In planning for the workshop it is hoped that all interested parties will be included in the attendance and that the workshop structure will be built around small discussion groups including the totality of interests. Small groups with a give-and-take type of discussion will enable participants to more thoroughly examine the assumptions and orientation of other participants. Specific concerns will need to be addressed individually, and this will be possible only in smaller groups (given the time constraints of all involved in the proceedings).

It is hoped that the conference proceedings will be supplemented with other existing written material and sent to workshop participants sufficiently prior to the workshop so that there will be an opportunity to review the material and reflect on the issues. With workshop participants working from the common background of the conference proceedings and supplementary materials, it may be possible to arrive at some valid conclusions that will be useful in assessing coal's place in the California energy mix.

In judging the energy policy options open to California, coal utilization can not be judged in a vacuum, but rather should be considered as one of many alternative energy sources. This issue needs to be addressed in further detail at the forthcoming workshop. Specific policy questions might be:

1. What role should coal play in the future energy mix for California--both long term and immediate future? How does it compare in cost (both ec-

- onomic and environmental) with other energy sources?
2. If it is to be a "transition source" to bridge the gap from now to 2000 or 2010, what policies are necessary to ensure the development of alternative sources by that date and to avoid reliance on a "coal fix" to the exclusion of other sources?

One argument for dealing with this issue first is that if there is agreement among the parties that the need for coal is clearly established, then the other issues will of necessity be resolved. Alternatively, if the other issues are discussed first, there will be a better understanding of the impacts of bringing coal to California. In the second case, the determination of the role of coal could be made with an understanding of the real cost.

If coal is to be a part of the energy mix in California, then the following issues need to be discussed and resolved:

- a. Transport and availability: given the problems identified at the conference, what could the public sector do to alleviate the problem? What remains to be resolved by the private sector?
- b. Environmental aspects: there needs to be a clearer definition of the environmental problems associated with coal utilization for both direct firing for boiler operation and other technologies. A discussion (and agreement) on siting criteria would help expedite the regulatory process. For example: what environmental aspects should be considered for developing acetate overlays? Which take precedence or priority?
- c. Economic Issues: Are incentives desirable? What state policies can be developed to provide incentives for coal utilization? Is there a need for state assistance in providing capital requirements? If so, what form should it take?

- d. Regulatory Issues: It is not clear that agreement can be reached on the issues identified by the various panelists of the last session. However, Jim Walker posed an intriguing challenge worthy of further discussion: How can we fund increased citizen participation in an innovative way to help the public understand the issues and have a voice in the process without just funding more expensive consultants? Can we devise a negotiating process wherein all parties bargain in good faith?

The League of Women Voters of California realizes the importance of energy source decisions and is particularly concerned that citizens find the decision making process open to their input. We urge the California Energy Commission and the Department of Energy to continue the dialogue on coal utilization in California and to make every effort to provide for broad-based citizen participation in that dialogue.

June 1, 1978

CONFERENCE ON COAL USE FOR CALIFORNIA
PASADENA, CALIFORNIA MAY 9, 10, and 11, 1978 JUN 6 1978

Report To: California State Energy Resources Conservation
and Development Commission

From: Americans for Energy Independence, Los Angeles
Chapter

Prepared By: Robert E. Kettner (AFEI Representative at
Conference)

BACKGROUND: The following was published in advance as general
information:

"PURPOSE - The purpose of the conference is to provide a forum for the technical exchange of information between various elements of the coal energy delivery system community that are interested in expanded use of coal for California. Additionally, the conference is to provide a mechanism for examining the technological, institutional, and social issues surrounding coal use for California and to identify attendant constraints, impediments, advantages, and target opportunities. Major focus will be on the unique California energy infrastructure, environment, and geography and on the applicability of state-of-the-art and emerging coal technologies. The conference, which is being held at the Pasadena Conference Building, is being organized by JPL/Caltech and cosponsored by the Department of Energy and the California State Energy Resources Conservation and Development Commission.

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CONFERENCE STRUCTURE - The three-day conference will consist of a series of eleven plenary sessions of presentations and panels dealing with issues and activities central to that session's theme. The panels, that follow the papers presented, will be comprised of chairman's summary and question-and-answer period with the session speakers. A conference proceedings will be published documenting the presented papers, summary statements, and question-and-answer periods that ensue.

ATTENDANCE - Attendance is open to the public on a first-come, first-served basis and will be limited to approximately 600 persons."

REACTION TO THE CONFERENCE

ORGANIZATION AND SPEAKERS

The Conference was organized quite well with respect to issues and interests pertinent to use of coal for California. The speakers and their affiliations were well rounded and adequately provided the environment for examining the technological, institutional, and social issues surrounding coal use for California. There were notable exceptions to the conference representation; namely, the American Indians and their tribal nations. Although, as stated above in the conference purpose as being for those "that are interested in expanded use of coal for California," there were a number of outspoken participants who were not interested in the expanded use of coal for California. Therefore, it would have

ORGANIZATION AND SPEAKERS Continued

been appropriate to include representation from other voter action groups such as utility shareholders, union organizations, etc.

CHAIRPERSONS

Panel chairpersons, with exception of Jim Walker, were not effective in making deliberate and cogent summaries of the highlights and key thoughts expressed in the presentation of papers by the panelists. Frequently these leaders did not manage the allotted time of the speakers and thus clobbered the question and answer period, all important for this sort of conference to provide value to the State....Unless by design..the intent was to "orchestrate" a "show" with just enough "window dressing" to make it look real to those to be categorized as naive. At any rate, it was most frustrating to find precious time elapse and the elimination of time with freedom for all variety of opinion to exposure through questions. Unfortunately far too frequently the sponsor (JPL and CEC) staff personnel were allowed to monopolize the question periods to pursue individual advocacy positions and even whims without time for questions from outside independents and the public. The Banquet speaker was allowed to exhaustively explore a total background with history and tedious facts for almost one hour and forty minutes without the host sponsor doing anything to suggest that the talk should be ended. This was most unfortunate and awkward to say the least.

ATTENDANCE

The conference attendance was below expectation and considering the impact of the subject on Californians should have been oversubscribed. Perhaps the amount and timing of advance publicity is the best explanation. At any rate it was a conference that could and should have been better attended because of the topic. It was not one of the better conferences that I have attended. It was a disappointment that our Governor was not more inspirational and effective with kickoff of the conference. The late arrival of Chairman Maullin - after the Governor's remarks - was most revealing of individual priorities.

IMPORTANT VIEWS EXPRESSED

The views expressed for Californians to take note of, as seen by myself as one of the participants are summarized as follows:

USE OF COAL WITH NUCLEAR

Coal and nuclear are commercially available to California and should be used in partnership with conservation and other energy sources not as plentiful or economical. Base load generation of electricity from coal is probably a necessity within the state rather than "coal by wire" or "water." California's neighboring states have learned from unfortunate experiences with oil, gas, uranium and coal on how to more effectively deal hard-nosed with California. Henceforth a solution for use of coal by California must be satisfactory to neighboring states. In fact only Alaska

USE OF COAL WITH NUCLEAR Continued

is eager to sell coal to California in spite of their frustration with the delays from California politics relative to energy from the north slope of Alaska. Water may be the most sensitive issue in the use of coal requiring the equivalent of two tons of water per ton of coal used. The coal supply required for California could be from 6 to 10 quads with 45 million tons per quad. One 800 MWe electric generating plant requires 2 million tons of coal per year for a reasonable operating life of 35 years. It probably takes as long today to develop and put into operation a single coal mine in the West, as it does to build the power plant. Coal for California's use will essentially come from underground mines with 40 percent recovery of the coal reserve at best. There is plenty of coal for California when it gets its act together properly.

HOW OTHERS VIEW CALIFORNIANS

California, as seen by others outside the state, with energy sources needed by California, has a large responsibility to achieve most ambitious goals for conservation in order to deserve coal and uranium. Although California has been spoiled by low cost gas for over 26 years and consumes more energy than most other states energy consumption/capita is reasonable - even low.

NATIONAL COAL POLICY PROJFCT

The National Coal Policy Project is providing industry environmental cooperation with more effective communication using rules of reason. Significant conclusions reached include: location of power plant close in near the user unless overwhelming reasons to the contrary; consolidate hearing process to a single event of course with better advanced notification from the utility; create deadlines for decisions; EPA allowed to have exceptions from new standards to enable to use by demonstration of control technology and let utilities use multi-step pricing based on marginal cost to the utility.

CONSUMPTION PROMPTS URGENT NEED FOR COAL DEMONSTRATION PLANT

California consumes 8-9 percent of total energy used in the United States. California, with 22 million population is big enough to compare with world nations. Therefore, the potential for failure to develop adequate energy supplies, satisfactory to neighboring states, is very real and most harmful. The technology is available and proven overwhelmingly elsewhere in the United States (45 percent of total electricity comes from coal). Coal cannot be both clean and cheap. California utility economic studies, at 1978 price levels for life cycle power costs, place coal with cleanup at 7¢ with nuclear at 6¢ and integrated combined cycle at 9¢.

CONSUMPTION PROMPTS URGENT NEED FOR COAL DEMONSTRATION PLANT Continued

The use of coal in California is unusual as essentially the state has no reserves within its boundaries. There is no coal being mined in California today. However, coal is only immediate choice because of discouraging decision recently made on nuclear. Hence appropriate use demonstrations of coal are necessary to meet the current realistic growth rate for electricity in California.

IMPACTS ON CALIFORNIANS

Coal is and has been a very economical source of energy for most of the United States, including California. Coal is required, should, and will be used to generate electricity for Californians within the state boundaries. There is an urgency to begin construction, within the state, of "demonstration" plants to generate electricity to provide public recognition of their need with resolution of societal problems within political and regulatory bodies.

The California voters in 1976 overwhelmingly approved the necessity to use nuclear for electricity production within the state, while political and regulatory processes have blocked implementation. Therefore, coal becomes the immediate proper choice, but coal brings with it a large number of environmental impacts coupled with a reputation for being dirty and including at least one of the most hazardous occupations (underground mining) in the United States today.

IMPACTS ON CALIFORNIANS Continued

The visual impact of the plants is not photogenic. Mining operations require decades to restore the environment. The land use requirements are great with a 1000 MWe electric generating plant requiring upwards of 2000 acres.

In a nutshell, our technology cannot solve all impacts, but certainly can improve the quality of the impact. Of course, if coal is to be permitted by Californians in California it must be viably economic and environmentally compatible. Coal cannot be both clean and cheap. Coal is clearly the most rational choice today for large boilers as far as fossil fuels go, yet unfortunate, it is probably one of the worst fuels from an environmental standpoint.

AMERICANS FOR ENERGY INDEPENDENCE ARE IN FAVOR OF COAL USE

"Coal is among the most promising near term energy resources" stated the President of AFEI, Joe Kennan, in his address to the Southern California Chapter at the 1977 Annual Meeting.

More specifically from "A Statement of Purpose" of Americans for Energy Independence.

"In the near-term, therefore, we have no choice but to concentrate our greatest efforts on, and to allot our major resources to, using those domestic energy sources which are available now and for which the technologies and capabilities exist. In specific terms, we need to put more management, money, and manpower into

AMERICANS FOR ENERGY INDEPENDENCE ARE IN FAVOR OF COAL USE Continued

developing our vast coal reserves; into making nuclear power serve a larger role in our total energy mix; and into increased exploration for oil and gas, especially on the continental shelf. Sufficient experience demonstrates that all of these things can be done in a safe and environmentally acceptable way."

The President of AFEI has further expressed the following views.

"The second key component of an energy policy should be the aggressive development of domestic resources.

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A few middle Eastern countries currently control the availability and the cost of almost half of the oil this nation uses. Our political and financial independence, our economic well-being and national security are jeopardized by this reliance on foreign sources. A large share of fuel demand now met by oil imports must be replaced with domestic resources.

As an immediate action, programs to locate, develop and bring into market new supplies of oil and gas, such as offshore drilling and the construction of pipelines, must be accelerated. This oil and gas will be urgently needed for use in homes and facilities in which the nation has invested billions of dollars that cannot be reasonably converted to use coal or electric power. Above all, oil is needed for transportation where no viable alternatives exist at this time.

AMERICANS FOR ENERGY INDEPENDENCE ARE IN FAVOR OF COAL USE Continued

Our abundant supplies of coal and uranium must be developed and put into widespread use to provide for near-term growth and energy needs. Efforts to accelerate energy production from them must no longer be thwarted by indecision and inaction.

There are problems with both of these fuel resources which I admit must be worked out. But they can. I have great faith in American ingenuity and our ability to solve problems.

I believe that the nation should focus on the most promising of these new energy concepts and devote our best research and development efforts toward realizing their potential. In the meantime, we must rely on energy conservation and on existing energy resources of oil, gas, coal and uranium while these newer sources are being developed, perfected, and put into practical use. We cannot put the brakes on the economy while we spend twenty to thirty years perfecting new technologies."

From the first of a series of advertisements in Readers Digest.

"America will not go out of business when we drain our last barrel of oil. Not if, during the time it takes to switch to other sources of energy, we: 1) make our oil and natural gas last as long as possible; 2) don't make it impossible to increase our use of coal or 3) of nuclear energy.

We have enough coal under U.S. soil for at least 250 to 300 years. Nuclear power now supplies 9% of our electricity. Uranium, used in nuclear fission, could amount to two thousand times our present fossil fuel base. In the future, another form of nuclear power -fusion- will use deuterium, which can last over 500 billion years! Eventually, we will know how to use this and other bountiful energy. But first, we have to get through an in-between period."

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From the second of the Readers Digest series.

"Our hope lies with other fuels which we have in spectacular abundance: Coal reserves of some one trillion tons! That equals the energy potential of the whole world's oil reserves. Uranium reserves for nuclear power may equal the energy potential of ten trillion tons of coal. We know how to use these fuels - coal and uranium. But bringing them up to take over from oil and natural gas will require solving very serious problems.

Consider just one problem with significantly increasing our use of coal: the problem of transporting it from coal fields to power plants. That takes railroads. But we must greatly expand our rail capabilities to handle the enormous job. For example, electric utility companies are now building coal plants in Texas, Arkansas and Louisiana. To fuel only these plants after they fire up in the mid 1980's, coal trains one mile long will have to leave western coal fields every hour, around the clock, every day of the year.

Clearly, coal and nuclear power offer the only practical sources to handle the growth in America's energy needs at least to the turn of the century. A generation ago, coal supplied 48% of our energy; today it's down to 20%. Yet coal comprises 81% of our domestic fuel resources."

From the third of the Readers Digest series.

"The Immediate Future, 1976-1985: Call this a breath-holding period. Because we must still rely mostly on oil and natural gas. Will the oil exporting countries let us buy what we need from them? Will we pump enough of our own - and conserve enough of all we have, both imported and domestic - to make it?

This is also the lead time period in which we must move vigorously toward higher coal production and also more nuclear power.

Though coal represents America's most abundant fossil fuel, we need a long lead time to get at it the right way. We can't just go back to oil-time coal mining. Deep mines must be increasingly mechanized and made safer. We must "scrape" much of our coal from near the ground surface, and rebeautify the land afterward. We must burn the coal according to new technologies that reduce sulphur emissions to harmless levels. We'll need new and expensive manufacturing plants to convert coal into synthetic gas and oil to extend our use of these fuels.

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We must do all this while trying to greatly increase our coal production, and we are lagging in that. A year and a half ago, President Ford set a goal of 1.2 billion tons for 1985, which seemed reasonable. But since we've done nothing significant yet - in fact, 30% of the planned coal plants have been canceled, not one demonstration plant for coal conversion has been built - plain arithmetic shows the date ahead to 1987, and the 1985 goal has been lowered.

From the third of the Readers Digest series. Continued

At the same time, rising prices have made the construction of new installations more costly, thus slower to attract investment capital. Labor with skills to mine coal and build railroads to transport it has drifted to other trades. So a job we once estimated at 10 years may take 12, if we start now and push hard.

The Intermediate Future, 1985-2000: Coal and nuclear power will supply most of our energy, but only if we have already done the big job on coal and only if we make full use of our nuclear option. We'll still be burning some oil and natural gas. And a small percentage of our energy will start to come from such sources as the sun.

In this period, nuclear power will have to carry a continually larger burden of generating electricity. It can do so, but only if we once again remain conscious of lead time. Today, some 20 years after the first commercial nuclear plant at Shippingport, Pa., 59 plants provide 9% of our electricity. It takes about 10 years to build a nuclear plant, and, according to a Bureau of Mines study, we'll need 900 of them to carry the load by 2000.

But, as with coal, we're standing still on nuclear power - drifting backward, in fact. While we have debated over it, half the proposed new plants have been canceled or delayed.

From the third of the Readers Digest series. Continued

The Future Beyond 2000: Assuming we've taken the right course, we could be in safe waters. Our coal resources could last several centuries at least. New nuclear reactors called "breeders" actually make more fuel than they burn. And, in 25 to 50 years, some of those promising energy sources of the future - solar, wind, tides, geothermal, biomass, fusion - should be working to make electricity on a large scale.

At the moment, solar energy seems most promising for direct heating of rooms and water. Using it to generate electricity is another matter. As yet, we don't have the technology to build a practical demonstration plant. Which means we really have no hard facts on what to expect from solar or other future sources in the next century - only high hopes, if we use our lead time for all the research and development still to be done.

Which brings us back to the only sure course for us right now: Mine all the coal we can. Have the determination to go ahead with nuclear power. Try harder to open up the resources of the future. Meanwhile, since we're already behind, we must stretch our lead time by conserving energy especially oil and natural gas. That's where everyone can help right now! But conservation includes more than driving slower and turning down the thermostat. AEI has prepared a program for conservation by individuals and homeowners. We'll send you a copy free. Just send us the coupon".

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From the fourth of the Readers Digest series.

"But right now we also must take these actions:

- We must mine and use far more of our abundant domestic coal. We can and must do this while simultaneously maintaining environmental quality and safety standards. But we must remember that we do not have the luxury of considering aesthetics alone; we must consider, too, the absolutely essential necessity to keep this country working.

- We must proceed with our development of nuclear generated power, assuring the health and safety of workers and the public. We have done so now for some 20 years, ever since the first commercial nuclear plant and with 63 operating now.

It takes many years to build the plants and equipment to use these sources of energy. We must have them to take over from oil and natural gas. We already lag dangerously behind in what we must do. We must move decisively and fast."

The Southern California Chapter of Americans for Energy Independence reprinted the article from the Houston Engineer. It appeared in the AFEI Newsletter of January 1978.

COAL AND COGENERATION

"Albert J. Smith, President of Power Systems Engineering, Inc. of Houston, said in a speech before the Industrial Power Conference of the ASME that large-scale simultaneous generation of electric power and steam offers industry the best utilization of available energy resources.

Smith pointed out that coal fired cogeneration facilities become more cost effective as their size increases. For example, coal terminal facilities designed to handle 100 thousand tons per year would cost about \$2 million installed while a terminal handling 100 times as much coal would only require about 12.5 times the investment. Significant savings in the cost per delivered ton of coal are also available through large volume, long-term fuel purchase and transportation contracts.

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The same principle would apply to electric power generating equipment and environmental protection equipment, since costs for these items do not increase in direct proportion to the size of the plant.

Smith added that "in the boiler house itself the savings may be less dramatic." While large pulverized coal boilers are able to maintain a higher fuel efficiency than smaller stoker fired boilers, the stoker boilers may actually produce steam at a lower unit cost. However, it would be impractical and uneconomical to use stoker boilers in large installations.

COAL AND COGENERATION Continued

Because of the economics offered by large scale and the tremendous capital investment required, Smith said "the tendency is for industries to pool their demands and draw from multi-user facilities, but this would not preclude the development of smaller installations.

According to Smith, obtaining attractive financing will be the major consideration in the evaluation of these "special purpose" utility plants. Several alternatives are available to industry, including a joint venture of users or financing and operation by an electric utility company.

Smith noted that while the user-owned joint venture may result in the lowest unit cost of steam and power to the users, it ties up a substantial amount of their corporate funds. Third party financing frees these funds for use in product producing facilities."

GOVERNOR BROWN'S OPENING ADDRESS

California has very diverse energy future and we must not rely on one single source of energy. The Governor expressed his confidence that California would meet its energy needs, leading the way and be an energy innovator even an energy capital. California is taking the lead in conservation with electric utilities and soon gas. The coal possibility is very important because we have used oil, gas and nuclear. If we put an end to "horse and buggy energy planning" then we can find use for coal. He announced his formation of a "Clean Fuels Coordinating Council" and noted that particularly coal itself will require maximum coordination. He noted that there is a need to construct more power plants without saying what kind or where. He complimented the utilities on the lead they are taking and expressed determination that resistance to power plant additions will be resolved with trade off of new power versus environmental impact. This state is not slowing down job creation and inward migration which was up 70 percent last year.

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He noted that the participants have heard his views on nuclear - California has seven nuclear plants - should get coal on line to determine viability of both. The Governor feels that range of uncertainty on cost of coal is rather great. Coal and nuclear are competitive as cost of decommissioning and storage of nuclear must be included. He noted that there is a requirement for \$13 billion for waste disposal of nuclear for just plants already licensed.

RECOMMENDED ACTIONS

Use of coal in California is an economical and environmentally feasible choice and should begin immediately with conversion of an oil fired plant to provide a demonstration of direct coal combustion within California to generate electricity.

California should take advantage of experience of other parts of the United States which are more experienced in coal use. The key to economic use of coal is transportation which could be as much as 70 percent hence need for large power plants - following reasonable demonstration with medium size plant - to enable economies of scale.

California must continue ambitious goals for conservation with realistic public understanding of same to enable growth of electric power while being in a position because of conservation to deserve coal and uranium from our neighboring states.

CONFERENCE ON COAL USE FOR CALIFORNIA

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Note: These papers are not arranged in the same sequence as at the Conference; they have been grouped by subject matter, regardless of title or session.

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SUMMARY

On May 9-11, 1978 more than 350 people representing coal supply and technology, government, utilities and the public attended a 3-day Conference on Coal Use for California. It was sponsored by the Federal Department of Energy and the State Energy Commission. To summarize:

California must have more electricity in the coming years. We do not have gas; we must reduce imports of oil; the state refuses to permit nuclear power; the new energy sources are not yet developed; and other states refuse to generate electricity for us any longer. This leaves coal.

Coal is in abundant supply in the Western states, both surface-mined and in underground mines. Transportation to California (900 to 1,250 miles) will add appreciably to the total cost. The railroads believe they can handle 1,000 unit-trains, which are 100 cars each carrying 100 tons of coal, each year. It is doubtful if coal can be transported by pipeline because the coal-exporting states will not provide the necessary water.

The amount of coal required is enormous: for one plant, it takes 2 to 4 million tons a year! A 1,000 MW power plant also takes 15,000 acre/feet of fresh water a year, or more if the water is salty.

Present plans are to burn coal to generate electricity in the Imperial Valley, the eastern California desert, and in the northern part of the state.

Governmental agencies without direct experience with coal, are very optimistic that coal can be burned without emitting any more air pollution than comes from burning low-sulfur oil or gas. Industry, and those agencies who have worked with coal, point out that many of the pollution control devices needed are not yet developed to a commercial stage. They may not be available in time for the scheduled plants in the late '80s.

Ways to burn coal cleanly include pre-cleaning the coal; using fluidized bed; scrubbers to remove sulfur oxides; baghouse or electrostatic precipitators to remove particulates; and probably ammonia injections to lower nitrogen oxides. Of these, only the precipitators are in common use. Scrubbers are being introduced, and no doubt will be required in California. Ammonia has been used only on oil-burning plants in Japan.

There was no discussion of the harmful effects of the sulfur and nitrogen oxides, particulates and toxic metals emitted from coal combustion.

Coal conversion to clean-burning gases and liquids is technically feasible but extremely expensive and not yet commercially available. Several processes are now in the pilot-plant stage, but it will be 10 to 20 years before we get much clean fuel from them.

Electricity produced in this state from coal will cost more than from nuclear plants. The final cost will depend largely upon the pollution control devices required.

Rebecca H. Sparling
for
American Association of University Women

PARTICIPANT'S REACTION TO THE CONFERENCE ON COAL USE

The Conference on Coal Use was extremely informative, and I thank you for making it possible for me to attend. It was an excellent plan, to get together the suppliers, users, support technologies, regulatory agencies and the general public. I am sure that each one of us, no matter what our background, learned many new things. The various papers covered the whole scope of coal use, from the need to supply, transport, techniques for burning, conversion to liquid or gas, environmental effects, and economics. The Conference was well planned and went off very smoothly.

It is evident that the State has already made the decision to use coal. Throughout the three day meeting, the feeling was one of optimism. Coal does present problems, we were told, but they can be solved. We saw pictures of clean clothes hanging in the basement by a coal furnace; we heard of developments which make coal burn cleaner than oil, almost as cleanly as gas; we were told of billions of tons of coal just waiting to be used in California. Surprisingly, there were few protests from the environmental groups who were so effective in stopping coal-fired power plants in other states, even when the power was destined for California.

During the meetings, everyone was swept along on the enthusiasm and optimism of the main speakers, who mentioned potential problems but without emphasis. Now that I am home, reviewing the 90 pages of notes taken during the sessions, I find a number of warnings. Coal cannot be both clean and cheap; air pollution controls have been demonstrated in small scale, not on a real power plant; none of the so-called "clean options" for burning coal or converting it to gas or liquid, is yet in the commercial stage; the amount of water required is tremendous!

For years now, I have advocated the maximum use of both coal and nuclear consistent with environmental concerns, to reduce the imports of oil and gas. I still believe this should be our national policy. But I fear that burning coal cleanly in California will be much more complicated and expensive than I had thought. I do not even know if we can solve the air pollution problems in time for the coal-fired plants planned for the late 1980's. The solution will come, I am sure, but not next week or next year.

The one regret I have is that there was not enough time for more questions and comments from the floor. There were many statements which could profitably have been discussed in much more detail.

In the following pages, I shall answer the questions you listed, then provide a short summary of the notes I took of each paper. My notes are arranged by topic, not by session.

Respectfully submitted,

Rebecca H. Sparling

Rebecca H. Sparling
for
American Association of University Women

May 29, 1978

Rebecca H. Sparling
2282-C Via Mariposa West
Laguna Hills, CA 92653

1. VALUE TO THE STATE

The Conference was of real value to the personnel from State agencies. The 40 papers covered the need to use coal; supply and transport; environmental effects, especially air and water; direct firing; conversion to gas or liquid fuels; and the capital investment required. Everyone there must have learned a great deal, including the more than 50 state employees. But I think the Conference could have been much more useful in helping the State agencies make wise decisions, if the presentation had been more balanced. Except for Dwight Carey's paper, the general tone was that there are problems connected with the use of coal in California, but they are or can be solved -- without much emphasis on the time, money and work needed for such solutions.

The Conference did not provide a means for public concern about the use of coal, to be transmitted to the Commission at this time. Perhaps later, after those attending get home and discuss the topic with their constituencies, there may be a feedback. The public input was limited by:

a) Not enough people from the public sector. Most of the attendees were from the coal supply or technology industries; many were from government, some from utilities, and a few (around 10%) from the public. The public representatives were well chosen, from a wide variety of civic, ethnic, environmental, economic and women's groups. I found the Conference so stimulating and worthwhile that I am very sorry there was not more advance publicity to encourage attendance by the health organizations (cancer, lung and heart) the AARP, churches, etc.

b) Not enough time available for questions or comments from the floor

c) Not enough two-sided discussions to evoke questions. Later, as people get home and review their notes (as I have done) or get more information from other sources, I think there will be more expression of public concern on several items. During the Conference, we were sort of mesmerized by the rosy glow of optimism and confidence.

2. IDENTIFYING MAJOR ISSUES

The major issues identified and addressed were:

a) Why coal is needed; future demand for power	Sessions II and V
b) Supply of coal	" IV
c) Air pollution from direct firing of coal	" III and VI
d) Water Needs	" III and IV
e) Transportation	" IV
f) Liquefaction and gasification	" VIII and IX
g) Capital needs and economic considerations	" VII and X

(Identifying Major Issues - Continued)

These are probably all the really major issues, but there are three more which should be included in the discussion. These are

(1) Solid Waste Disposal. There will be fly ash, bottom ash, scrubber sludge --- not just a small amount, but thousands of tons. How will it be disposed of? What are the environmental effects of piles of ash? How will the scrubber sludge be kept away from groundwater?

(2) Effects of Cost. The three days of informative papers on the cost of mining, transport, cleaning and handling coal, made one thing crystal clear: Electricity from coal-fired plants in California will cost more than that from nuclear plants, and may cost a great deal more. Now, the price of electricity has a marked effect on other prices --- water, rents, taxes, manufactured items. Any unnecessary increase in the cost of power is a real disservice to the many citizens of this state who are on low or fixed incomes. Yet cost was hardly considered. When someone asked whether the cost of certain controls was excessive and whether it was warranted, the problem was just shrugged off. The conference agreed that our state needs an adequate supply of energy; but let us add "at a price we can afford".

(3) Mine Health and Safety. Chairman Maullin mentioned in his opening statement that this is a problem, and one other man termed mining "hazardous". That was the sum total of attention given to miners.

Perhaps people assumed that California would use surface-mined coal, but the most probable source for our coal is Utah or Colorado, both underground mined. In spite of improved legislation, there are still 125 - 150 miners killed each year in accidents, thousands more involved in disabling injuries, 3 to 4,000 dead from pneumociosis (black lung) and a couple of thousand new cases of black lung annually. Should we not consider the cost in human lives, as well as the cost in dollars, of satisfying our desire for electricity? When mines are opened for the specific purpose of supplying millions of tons of coal to produce power for California, how can we avoid all responsibility for the health and safety of the miners? Some companies have better records for attention to safety than others; this aspect should be investigated and should weigh heavily in the selection of a coal supplier.

It is true that mine health and safety come under Federal rules and under the control of the state where the coal is mined. But we can influence it, by our choice of surface- or underground-mined coal, and by our contract for that coal. We agonize over the fact that surface-mined terrain cannot be restored to its original condition; let us remember that a person with black lung cannot be restored to the original condition, either. People are as important as grass.

I hope that these issues can be addressed at the next Conference.

3. ADEQUACY OF COVERAGE OF MAJOR TOPICS

The coverage generally was very good. The program was complete (with the three exceptions I mentioned) and there was little repetition. But looking over my notes of the talks and comments, I find several subjects which could well have been treated in more detail. I hope some of these will be answered or explained at the next Conference.

a) Air Pollution

The main objection most people have to burning coal, is the resultant air pollution. People are really concerned, and need more information, especially about the control equipment for large power plants. Dr. Austin's paper told of wonderful results from new Japanese technology, and I got the impression that this would be required on coal-fired plants built in California. But discussion brought out that the Japanese project has been under way for about a year, using only the electrostatic precipitator and the scrubber but not the ammonia injection. Furthermore, the unit is only 0.4 MW size -- very far from an 800 MW plant! And of course, it burned Japanese coal. The ammonia injection so praised had been used only on oil-fired power plants, not on coal.

Certainly, the fact that this small-size unit works well, gives one great hope that it will prove out for commercial application. But we do not know how long it will take to build and test larger units, or what the effect of different coals will be, or how much it will cost: Japanese accounting procedures are rather different from ours. It would be easy to count on the ISOGO + ammonia controls, and to spend a billion dollars on a power plant to use them, only to find that they are not available when needed. Industrial experience of many years has taught me to respect the importance of the scale-up factor: problems do appear, in large size, that were not encountered or foreseen in small items. A woman who bakes well, and always gets compliments on the decorated birthday cakes for her children, may open a small bakery. Perhaps she succeeds and grows, and enlarges, and finally even challenges the giants of the baking industry. But she does not go directly from her own kitchen -- or even the kitchen of her club or church -- into a multi-million dollar bakery and expect perfection!

I believe the following should be considered:

- (1) Are any large coal-fired power plants in Japan installing the ISOGO system? or ammonia injection? If not, why not? (Maybe they know something we don't.)
- (2) What is the best way to test ISOGO and ammonia, step by step?
- (3) What time schedule is involved?
- (4) What effect does coal composition have on performance?

b) Radioactive Wastes

When coal is burned, some radioactivity is emitted as gases, and some is retained in the solid waste. Perhaps the amount emitted is insignificant, as from nuclear plants. What are the levels, and what isotopes are involved?

(Coverage of Major Topics, Continued)

c) Toxic Metals

The toxic metal emissions were mentioned in discussion, but in no detail. The particles of concern are so small that they are not removed by baghouse or electrostatic precipitator; some are removed in scrubbers, but we do not know how much. The 14 metals I have seen listed, as present in exhaust gas from coal combustion, are antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, molybdenum, nickel, selenium, thallium, titanium and zinc. Some are carcinogenic. We should investigate the amount and significance, of these toxic metal emissions.

d) Effect of Electric Cars

Ms Nichols of Air Resource Board said that by 1990, half the new cars sold in California would be electric. This will reduce the smog (oxidant) from cars; but it will require more electricity to be generated. Since we do not have clean natural gas to burn, and the state forbids clean nuclear power, and both Federal and state policy is to cut down on imported oil, this additional electricity will come from coal-fired plants. How many additional plants will be needed?

Will the electric cars clean up the air in urban areas, only to pollute the desert where power plants are sited? We need a comparison of the health effects of reduced oxidant, versus the adverse effects of increased SOx, NOx and particulate from burning coal. Perhaps this is not in the province of the Energy Commission, but certainly you must be involved in providing the power to run these electric cars.

e) Water Supply

Several speakers emphasized the tremendous amount of water that will be needed to transport coal, to gasify it, or to generate power from it. The other states are quite frank in saying that since California refuses to face up to its energy needs (as shown by the refusal to build Sundesert nuclear plant) they will not use their resources, or consume their water, in generating electricity for us or in sending coal slurry in pipelines. It is clear that we must provide the water for our own electricity. There are three areas which were either ignored or just touched on lightly:

(1) Future need for water

Population projections indicate that we will need much more water in 2,000 than we use now; yet in the 1980's, we will lose much of our Colorado River water to Arizona. We were told that the Metropolitan Water District can furnish 100,000 acre-feet of water a year from Colorado River water for power plant cooling. Will this amount be available after 1985?

(Coverage of Major Topics, Continued)

(2) Supply of Water in the Desert

As I lived in the desert for 15 years, it was a real surprise to hear that there is enough wastewater and groundwater for power plant cooling at such locations as Barstow and Cadiz. Right now, the Mohave Water Agency (of which Barstow is a part) is suing Edison for release from a contract to supply water for a future power plant. They claim they must use the water to replenish the present overdraft. Mining groundwater (if it is there) would severely lower the water table and deplete the supply for future use. The forthcoming survey of groundwater supplies in the eastern California desert, prepared by the U.S. Geological Survey, should be consulted before siting any power plants in that area.

(3) Cost of Water

A big part of the cost of water is the electricity needed for pumping and distribution. The State Water Project now uses 5½ billion KWh/yr for these purposes. When the present contracts for power to bring Colorado River water to California expire, there will be an enormous jump in the cost. Similarly, Feather River water is expected to go up by several hundred per cent in the next few years. Since the cost of water and electricity are so inter-connected, more attention should be paid to the probable change in water prices between now and 2000.

4. OVER-ALL BALANCE OF CONFERENCE

The balance was pretty good, in terms of the amount of time allotted to the various topics (although I would have liked more time spent on water needs). But when we look at the background of the speakers, we see 15 from coal supply and technology industries if we exclude the 7 representatives from coal-producing states; 11 from governmental agencies; 6 from utilities; and 4 from the public. Or maybe 5 public, if we count the Sierra Club member who was chairman of one session and gave his views. It hardly seems that 3 Sierra Club members, one banker and one man who was probably a lawyer, adequately represent the more than 20 million residents of California. It would have been good to provide for more speakers from the public sector, to present our questions and point out our concerns. It would have been helpful if some of us had been furnished advance copies of the papers, so we could prepare comments. Or if there had just been more time for public comment at the meetings, that would have helped.

The public's main concern, air pollution, was well covered. But there are other factors which affect the public, too: whether we will have an adequate reliable supply of power, and how much it will cost.

POSITION OF THE PARTICIPANT'S CONSTITUENCY ON COAL USE

The 31,000 members of California State Division of the American Association of University Women are all college graduates, interested in the community and active in working for a better California. Our Legislative Program for 1977-79 includes the following commitments:

- (1) Conservation, comprehensive planning and wise utilization of resources, including land, water and energy sources
- (2) Protection of the consumer
- (3) Control and management of environmental pollution
- (4) Improvement of the social and economic status of the elderly
- (5) Citizen participation at all governmental levels

We are, therefore, extremely concerned about energy sources, supply, cost and effects. AAUW established a blue-ribbon committee to study nuclear power for two years, then the general membership adopted their resolution to continue nuclear power, in 1977. We have done no such study on coal, and have no position for or against its use in California.

Our lack of attention to coal as an energy source comes from several things:

- (1) Many members feel (as Ms Nichols of the ARB said) that we have a glut of oil and there will be plenty for several years. They see no immediate problem. But power plants cannot use this oil.
- (2) Some cannot believe that coal is even being considered, because of the air pollution!
- (3) They do not realize that coal is the only fuel available in large supply for this state for the next 10-25 years. We do not have gas; solar is not here yet; there is little new hydroelectric; geothermal is not developed; the State cannot decide whether or where to permit imports of LNG; and the State will not permit nuclear plants. Coal is the only thing left.
- (4) As long as the lights go on when they push the switch, many people will just ignore the problem of energy supply.

MAJOR POSITIVE EFFECTS

The one big positive effect of burning coal, is that it will reduce the imports of oil and thus help restore our independence as a nation. As long as our economy depends upon the good will of foreign oil suppliers, we cannot be truly independent. Coal is abundant in the United States; its use will create more jobs; with coal as the energy source, we can be assured of adequate power.

MAJOR NEGATIVE EFFECTS

Constraints of time prevented taking a poll of AAUW members, but I did put the question of coal use to a group of some 100 AAUW women. Five hands went up FOR; 85 upraised hands, boos and stomping feet answered my call for those AGAINST. Their reasons: Coal is dirty; it pollutes the air; it is a step back into the 19th century; it is unnecessary -- why not have solar electricity? It is unfortunate

Participant's Constituency - Continued

that those pushing solar use have not differentiated between solar water heating -- which is here now, if you can afford it --- and solar-generated electricity which is NOT here and will not be, for many years. Some simply could not believe that burning coal in California is under serious consideration.

RECOMMENDATIONS

I suggest to the President of CSD-AAUW that she provide each of the 168 branches a summary of my report, and draw their attention to the problem of a fuel for electricity. I hope that each Branch will start a study group to learn about coal use, since it will affect every one of us and especially those living in the desert regions, or in other areas where coal plants are planned. At least, each Branch could hold a meeting or series of meetings, perhaps debates For and Against, as we did on the nuclear question. We must become better informed on the subject of coal use in California.

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GOVERNMENTAL POLICY

Both State and Federal spokesmen emphasized the need for power in California, and the necessity for using coal to replace oil or gas. Gov. Jerry Brown is appointing a Clean Fuels Coordinating Council to resolve the problems of air pollution; the obstacles can be overcome. The state must have a balanced mix of energy sources. Dr. Felix Mills of the Department of Energy told of their work on clean combustion and on gasification. Synthetic liquids and gases can be made from coal: the major constraint is the cost of facilities and development. Dr. Richard Kaulin, chairman of the Energy Commission, was equally optimistic. Modern coal-fired power plants emit no more sulfur oxides and particulates than oil-fired plants, he said, and there is a new way to clean coal to remove the need for stack clean-up. This new system may be commercial by the late 1980's.

GOVERNMENT INCENTIVES

Russell Bardos of DOE said there is no commercial experience in this country with any of the coal technologies except direct firing in boilers, and a few low-BTU gasifiers. However, AFBC (atmospheric fluidized bed combustion), coal/oil mixtures, and low- and medium-BTU gasification are commercially available. Companies hesitate to try these unproven processes; they do not know what the return will be, how national policy may change, or what future environmental limits will be. Since there is no coal in California, each company would have to arrange transportation from another state.

To show the advantages of some of the new coal technologies, DOE is sharing the cost of demonstration projects on high-, medium- and low-BTU gas, on AFBC and on coal/oil mixtures. The energy bill may provide tax incentives, but no one will know until it is passed.

The Government can cut oil imports, but we are not ready (technically, financially or environmentally) to fill the gap. Synthetic fuels are not yet competitive on the market.

GOVERNMENT REGULATIONS - the Utility's View

David J. Fogarty of Southern California Edison (whose paper was read by Douglas White of SCE) says that Edison needs to add 500 MW/year through the 1980's, to maintain reliability. The multiple permits required, the detailed studies and reports, the many hearings, all increase expense and extend the lead time to build a plant.

There is conflict between governmental agencies, too. Air Resource Board rules could prevent siting power plants almost anywhere in the state. Department of Water Resources doesn't want inland water used for power plant cooling; but the Coastal Commission can unilaterally prohibit power plants on the coast, where they could use ocean water. The NOI (Notice of Intention) was originally meant to be for screening sites, but has become a very detailed study of everything about each site proposed. It would help if the Energy Commission and the Public Utilities Commission could conduct their review of power plant applications at the same time, instead of consecutively.

GOVERNMENT REGULATIONS - the State's View

Ms. Mary Nichols of the Air Resource Board (ARB) defended the present regulatory system. She feels that the multi-agency system is appropriate to our modern society.

ARB has not taken a position on coal. It is possible, within the costs of nuclear, to generate power from coal as cleanly as from gas. In the future, our electricity will be generated within this state. Rail transport of all the coal needed would cause problems -- noise, land use, esthetic impact -- but the coal exporting states do not want to provide their water to ship us the coal in pipelines. Perhaps we could ship California water to the coal mines for the pipeline slurry, or give up some of our Colorado River water to the coal exporting state.

In the discussion, Ms Nichols said there is no hurry about using coal: we have a glut of oil in California, with no crisis in sight for at least 5 years. (Note: ARB rules prevent using the available oil for power plants; they must import low-sulfur oil.)

She feels all areas in California should have air quality better than the federal Air Quality Standards. Utilities may have to reduce NOx emissions by 90%, regardless of the cost. ARB will also move vigorously against cars, buses, trucks, motorcycles. By 1990, at least half the new cars sold in California must be electric. Someone asked if she had told the utilities or the Energy Commission about the electric cars, which will take a lot of electricity; she had not.

DEMAND FOR ENERGY

Mike Jones of the Energy Commission explained why new power plants are needed in California: (1) to meet the needs of increased population; (2) to retire old inefficient plants; and (3) to provide more flexibility in the generation of power, with some baseload and some peaking plants. Originally, the utilities had planned to meet most of their 1976-95 needs with nuclear power.

Ned Griffith of ARCO gave his personal opinion of the next 15 years. The GNP will grow 3.4% a year, and energy consumption will go up 2.4% a year, assuming that world oil prices remain constant except for the effects of inflation, and that U.S. oil prices equal world prices by 1985. Coal use will be encouraged and nuclear will be discouraged, but not actually stopped. The major sources of energy for California up to 2,000 will still be oil and gas, although they are scarce and expensive. But by 1990, both coal and nuclear could make a significant contribution.

COAL SUPPLY

Orson Anderson of UCLA, chairman of this session, said that California now consumes 6 quads (quadrillion BTU) of energy a year. Assuming that Gov. Brown wants to get 30% of this energy from coal, we must bring 90 million tons of coal into the state each year! The magnitude of the undertaking is staggering.

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COAL SUPPLY (Continued)

Joseph Yanick, representing the National Coal Association, said there are enough coal deposits in Western states to supply California. Central Utah and Colorado have underground mines, while New Mexico and Wyoming have surface mines. If the coal is on Federal land, it takes 12 to 14 years to bring a strip mine to full production, or 15 to 18 years for an underground mine. Utilities must make a commitment for the coal at the same time they make the commitment to build a power plant.

COAL SUPPLY - View of Coal-Producing States

Colorado (Martin Robbins) will not become an energy colony. The control over coal mines is local, all the way down to town councils. Maybe we will form OCES -- the Organization of Coal Exporting States!

Utah (Richard Searle) plans to complete the 3,000-MW Intermountain Power Project, with 65% of the power earmarked for California. After that, there will be no more construction for export until studies have been made and a policy established. There will be no more coal slurry pipelines, either, unless the water is somehow returned to Utah.

Arizona (Tom Lynch) is at or near the top growth rate in the nation. It is already mining several million acre/feet of water each year to meet existing requirements. It must keep the air clean, as tourism is a big industry. All the coal in Arizona is on Hopi or Navajo land.

New Mexico (Nick Franklin) is a leading exporter of energy: 1st in uranium, 2nd in electricity, 4th in natural gas, and the 14th largest coal producer. New Mexico is under pressure to deplete its resources for the swimming pools and neon signs of California. California's moratorium on nuclear energy shows they want the advantages of electricity while the producing states get the detrimental effects; let the other states carry the burden. Plants for California must be built in California.

Wyoming (Lynn Dickie) is under tremendous strain because of greatly increased coal production. There is a responsibility to help meet legitimate energy needs, but there is tremendous waste in California. Wyoming's view is, consider all conservation and other sources first, before turning to coal. If coal must be used, burn it in California.

Montana (M. Stevens) has more than 32 billion tons of lignite and sub-bituminous coal in one 4-county area. Coal production has risen from 300,000 tons in 1960 to 28,000,000 in 1977 and is expected to reach 65,000,000 tons in 1985. It is impossible to restore the strip mined areas. We have no water for coal slurry pipelines.

Alaska (C. Quinlan) has a huge reserve of coal, more than 1,000 billion tons. Also, we have water. We have two goals: (1) to have enough new jobs for Alaskans and their children; unemployment now is 25% in the winter and 10% year-round; and (2) to diversify, to assure adequate income. Resource extraction is central to growth. Alaskan coal, or gas made from that coal, can become competitive in cost. But we are dismayed at California's reaction to receiving Alaskan oil and gas.

COAL TRANSPORT

Rail - Frank Guerin of Southern Pacific Railroad says the railroads can handle coal transport without too much trouble. They have unused capacity, and are interested in transporting large volumes of coal. By the time the other problems are solved, the railroads can handle 1000 unit-trains (100 cars of 100 tons coal each) a year, if the coal is located adjacent to an existing railroad. Southern Pacific carried 3 million tons of coal in 1977. (Note: not enough for one power plant.)

Pipeline transport of a coal slurry is economical and successful, according to John Lynch of ETSI. They carry 5 million tons of coal a year from Black Mesa to the Edison plant at Mohave, Nevada. Pipelines are underground, silent, and environmentally acceptable. They are now building a 1,400-mile pipeline from Powder River Wyoming to the Mississippi river, which will save Mid-South utilities a total of \$ 14 billion over the 30-year contract.

ENVIRONMENTAL ASPECTS

Joseph H. Oxley of Battelle Memorial Institute, discussing the non-electric uses for coal, sees little promise for utilization in the food industries. The pollution controls required are just too expensive. Pre-cleaning the coal and using AFBC help, but coal must be used with discretion. Flue gases contain SOx, NOx and hydrocarbons; the fly ash contains many elements which may be harmful. It will be 10 or 20 years before the new technologies provide clean power from coal.

R. Sextro of the Sierra Club said the main environmental effects of using coal come from (1) mining, whether surface or underground; (2) transport -- there are many rail accidents hauling coal; (3) plants to generate electricity, which emit air pollution of SOx, NOx, particulates, polycyclics and trace elements, and also cause thermal pollution by discharging heated water; (4) carbon dioxide released from coal combustion, which may cause climatic effects (the greenhouse effect); (5) the water used; and (6) occupational hazards to workers.

Dwight Carey, also from the Sierra Club, said coal mining disrupts the region, pollutes the water, disturbs wildlife and vegetation. Liquefying or gasifying coal consumes water and contributes to air pollution. Coal-burning plants emit air pollutants, and have to dispose of a tremendous amount of solid and liquid wastes. California cannot rely on coal in a big way; coal is not a panacea; it cannot be both clean and cheap.

Mike Eaton of the Sierra Club staff, voiced his concern about the regulatory process. The public is turning to coal, but people are worried about pollution. They know a clean plume may still include many invisible pollutants. The problem is one of public acceptance of coal. Decisions should be made with public participation; the State and the Energy Commission should provide funds for consumer groups to participate in hearings.

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ENVIRONMENTAL ASPECTS ---- AIR POLLUTION

Dr. Tom Austin of ARB said that California will require plants to use Best Available Control Technology (BACT) even though it is not needed to meet Federal limits. (The Federal rules specify the amount of pollutants emitted and the resultant air quality, not the methods used to achieve compliance.) Dr. Austin described a Japanese ISOGO pollution control system which has an electrostatic precipitator and a wet scrubber. If ammonia injection is added to reduce NOx, the combined system would produce gases from coal cleaner than those from burning oil with 0.25% sulfur. He showed these figures, in lbs/million BTU heat input:

	NOx	SOx	Particulates
EPA limits for oil	0.3	0.8	0.1
" " " coal	0.7	1.2	0.1
ISOGO* on coal	0.34	0.1	0.035
Alamitos # 5, oil	0.17	0.26	0.049 (with 0.25% S oil)
Scattergood, gas	0.034	0.0008	0.0025
ISOGO with ammonia (?)	0.034	0.1	0.035
ARB ideas for California	0.1	0.05	0.01

Discussion showed that ISOGO has been tried for a year on a 0.4 MW unit, burning Japanese coal. The ammonia injection system has been used only on oil-burning plants, not for coal. When questioned if scaling up to an 800 or 1,500 MW plant, using different coal and designed for 30 year life, might be a problem, Dr. Austin said no.

Utilities must install BACT at the time they apply for a permit to construct, which is several years after the plant is designed and approved. If ISOGO with ammonia is BACT, it will be required. If a utility is made to install ammonia technology to achieve 95% NOx reduction, and it does not work, what then? he was asked. "If it gets 92% reduction, we probably wouldn't shut down the plant."

Dr. Austin said that both the State and the ARB would accept pollution trade-offs between air basins, if the net result was lower pollution. This brought objections from desert residents, who pointed out that clean air is one of their greatest assets.

Sulfur dioxide control was discussed by Frank Princiotta of EPA. It will be necessary to use FGD (flue gas desulfurizer) to reduce the SOx from coal to acceptable limits. There are 29 units in operation now and 51 more are on order. The first ones in 1972 had only 30% availability (time available/time wanted) but in the past six months, this figure has risen up 60 - 80%. A scrubber installed today should, after a six-months break-in period, have 90% availability. But there are other problems with scrubbers: stack lining failure, corrosion, scaling, etc. A large scrubber in mid-1977 cost \$ 70/KW; today it is \$80 - \$100/KW. Small units cost more per KW.

ENVIRONMENTAL ASPECTS - AIR POLLUTION (Continued)

Nitrogen Oxides, according to Donald Teixeira of the Electric Power Research Institute, can be reduced by using less air during combustion. This technique is being tested in a 0.4 MW facility, and may be commercial in the mid-1980's at a cost of \$ 5 to \$10/KW.

Or, according to limited Japanese data obtained on 0.1 MW units, ammonia can be injected after combustion. This process has to be scaled up before application to full sized plants. Possible problems with ammonia include deposition, plug-up, leakage, etc. The cost of ammonia treatment could be \$ 10 to \$ 80/KW; maybe \$30 is a reasonable average, but we just don't know.

Particulates can be controlled in two ways, according to Dr. David Hinz of Meteorology Research. One method is the electrostatic precipitator, which is quite sensitive to the type of coal used because changes in coal chemistry affect the resistivity. Precipitators must be designed for the specific coal burned.

Another way which has not yet been used in the electric generating industry, is with fabric filters or "baghouse". The largest one tried in a power plant to date had 600 bags. But a 500-MW plant will need 10,000 bags!

Particulates are any solid particles, of whatever size, shape or composition. Someone asked how to remove the sub-micron particles which may be carcinogenic, mutagenic, or polycyclic hydrocarbons -- not organo-metallics. The answer was, scrubbers will take out some of these particles, but we do not know how much.

The cost of particulate control is important. Peter Cukor of Teknetron said that in California, utilities must meet the federal NSPS - new source pollution standards; plus the states' new source review requiring BACT; and the local air pollution district's weight rules. For an 800-MW plant burning coal with 10% ash, this would require a reduction in particulates of 99.93%. The largest equipment capable of achieving this today, is for a 200-MW plant. So the cost of meeting this particulate reduction is unknown. However, an existing 800-MW plant burning 10% ash coal and getting 99.66% reduction in particulates, spends \$ 47.25/KW to achieve this level of reduction.

WATER

Ron Robie of the State Department of Water Resources said that any thermal electric generating plant needs about 15,000 acre/feet/year of fresh water for a 1,000 MW plant, and more if the water is highly saline. DWR wants to use urban and agricultural wastewater for power plant cooling wherever possible. Each plant is considered on its own merits, but the use of inland water for power plants is very low on the priority list. There is enough wastewater in Imperial Valley, where DWR plans to build a 1,000-MW coal-fired plant, but its use for power plant cooling would affect the salinity of the Salton Sea. The Eastern California Desert (Cadiz, Barstow, etc.) has enough ground and wastewater for power plants, but it may have to be mined. A U.S. Geological Survey of groundwater in this region will be published soon.

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COAL USE

An Overview of the various uses of coal was given by William Hathaway of Fluor, under the title of "Importing Coal-Generated Energy." We must have enough energy to sustain our economy, and we must substitute coal for oil and gas. There are many things we can do with coal:

- (1) burn directly, with pollution controls, to generate electricity
- (2) gasify and burn the gas in power plants
- (3) gasify in situ (done in Russia, not here)
- (4) burn with AFBC (atmospheric fluidized bed combustion)
- (5) MagnetoHydroDynamics, MHD
- (6) use in fuel cell
- (7) make high-BTU gas for homes and industries
- (8) make medium-BTU gas
- (9) make synthetic hydrocarbons such as methanol
- (10) convert to liquid fuels

Except for direct firing of coal in generating plants, all these uses for coal are still in the research and development stage. However, there are some pilot plant units now under construction.

AFBC (Fluidized Bed) was described by Mike Pone of Pone, Evans & Robbins. AFBC uses granular coal held in suspension in air. The coal is crushed, not pulverized; ash is caught in a cyclone collector, followed by baghouse or electrostatic precipitator. Limestone in the furnace bed helps keep SOx low. The system can meet present EPA limits of 1.2 lbs SOx per million BTU, but EPA is now revising these limits, so scrubbers may be needed. AFBC sounds good, but it is not yet a proven technology. There are 12 feasibility studies underway for industry at this time.

Coal Gasification: A high-BTU synthetic gas comparable to natural gas can be produced, says Joe Bern of Western Gasification Inc. The Lurgi process converts coal + oxygen + excess steam, at 400-450 psi pressure, to a synthetic natural gas (SNG). This crude gas is treated to remove CO, then methanated catalytically to CH₄ (methane). The process has been demonstrated in pilot plant, but not commercial size. But Lurgi is now willing to guarantee the process, which has been used for various things since the 1930's.

WESCO located coal in New Mexico, has the water allocation (not from the Navajo nation, but from the state's industrial development) and has many of the permits required. This project to produce 250 million cubic feet of gas a day, needs only two things: approval by the Navajo nation (and WESCO is looking for coal off the reservation), and financing. The project, estimated at \$ 457 million in 1973, will cost \$ 1.4 billion today.

Coal Gasification: Medium-BTU gas produced by a Texaco process, was described by that company's Warren Schlinger. This gas can be desulfurized for fuel for gas turbines. The technology has been used by some 70 companies over the past 25 years to make ammonia and other chemicals. Texaco has plants handling 15 to 20 tons of coal a day; there is one in Germany handling 150 tons a day. Edison will use this process to make gas from 1,000 tons a day for the gas turbines at its 90-MW combined cycle facility near Barstow.

COAL USE (Continued)

Coal Gas in Industry, said Lowell Miller of the Department of Energy, was common in the early 1900's but was supplanted by cheap natural gas. Today, gas can be made from coal in a single-stage gasifier which is simple and cheap; but the gas has tars and other constituents which are environmentally bad. A two-stage gasifier removes the objectionable oils and tars, and produces cleaner gas. Unfortunately, the two-stage system has not been tried on U.S. coals; it cannot handle coking coals or "fines"; and it has operating problems. Industry is not really interested in these coal gasifiers, because of environmental problems and the cost.

COAL LIQUEFACTION

Bob Hamilton of the Department of Energy gave an overview of the various type of coal liquefaction processes. Coal can be refined to a low-sulfur, low-ash solid fuel for boilers; or made into synthetic crude oil; or further treated to become naphtha or fuel oil. The high cost and uncertain future of synthetic fuels discourage industry from investing the money necessary to develop the techniques. DCE is funding pilot plants, as well as working on research and development.

SRC (Solvent Refined Coal) was described by George Chemoweth of Gulf Mineral Resources Co. In the SRC-I process, coal is mixed with distilled solvent and hydrogen, is reacted, filtered and may be gasified or vacuum flashed and solidified, to produce a low-sulfur low-ash coal for boilers. The SRC-II process uses twice as much hydrogen, but its end product is distillate fuel oil, plus some propane and gas. Gulf has a 1 ton/day plant, and operates a 50 ton/day pilot plant for the Government.

H-Coal (discussed by William Voss of Ashland Synthetic Fuels) uses direct catalytic hydrogenation at 5500 and 3,000 psi pressure to produce reformat, distillate, butane and propane. A pilot plant for 600 tons/day is under construction, jointly funded by DPE, EPRI, Kentucky, and the oil industry. Start-up is expected in the summer of 1979.

Exxon's "Donor Solvent" process was explained by Larry Swabb of that company. Coal is crushed, dried, slurried with a donor solvent and hydrogen, and then reacted. This produces naphtha, fuel oil, a little propane, with sulfur and ammonia as by-products. Construction is starting on a 250 ton/day pilot plant.

Methanol burns clean, with little SOx or NOx, no ash, and is biodegradable. Don Miller of Vulcan said methanol can be made from coal or lignite, and suggested conversion to methanol at the coal mine in other states, then shipping the clean fuel to California. A 5,000 ton/day facility could produce 15,000 barrels of methanol; but there is only one commercial plant now, and that is in South Africa.

Note: The coal liquefaction processes all get 1 to 3 barrels of oil per ton of coal, at a cost (in 1978 dollars) of \$ 3 or \$4 per million BTU. It will be quite a while before synthetic oil from coal replaces much of our present imports of some 8 million barrels a day!

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UTILITIES

Southern California Edison's vice-president Jack Mocre reported that Edison will need 5 to 6,000 MW additional generating capacity by 1995. He compared the cost of generation:

Nuclear	5.5¢/KWh
Coal, cleaned	7.0
Coal Gas, in combined cycle	9.0
Geothermal	10.0

Edison hopes to have a coal-fired power plant in the eastern California desert by 1987-9, but the pollution control systems required have not yet been demonstrated. SCE is undertaking two projects on clean burning of coal at its Barstow facility. An 81-MW unit will demonstrate clean direct-firing using baghouse and scrubbers and perhaps ammonia injection. The other project will gasify 1,000 tons of coal a day and use the gas in a 90-MW combined cycle plant.

Southern California Edison's Larry Papay described in more detail the "clean fuels" program. They will experiment with the 81-MW unit to get experience with baghouse operations, scrubbers to reduce SOx, disposal of solid waste -- fly ash, bottom ash and scrubber sludge --- and some means of NOx control. The various components have never been used together, so it will be a learning process; but it is hoped that they will meet pollution limits. It will take about 4 years to demonstrate this new technology. Data from the 81-MW unit will be used in the design of the 1,500-MW coal-fired plant planned for Cadiz, Rice or Vidal in the eastern desert.

Pacific Gas & Electric's N. Daines said his company plans two coal-fired plants. They are also working on conservation, coal gasification, geothermal, use of wood waste, and solar water heating. It takes at least 8 years to build a coal-fired plant. The necessary cleaning devices may become available during those years, but they are not here yet.

Converting from Oil or Gas to Coal involves many factors, according to J. Rau of Ultra Systems Inc. Is suitable coal available, and will it impair reliability or service? Things that must be considered include the size of the plant; its utilization -- whether baseload or peaking; the remaining useful life; the region and the environmental controls required; whether it is better to just build a new unit, rather than to convert; the type of fuel now used; and the company's ability to raise the necessary capital for conversion.

Life-Cycle Costs of using coal in California were treated by Charles Mann of Energy & Environmental Analysis Inc. For baseload plants, nuclear is somewhat cheaper than coal (Mr. Mann did not give any information on the pollution controls included). For industrial applications, none of the clean options for using coal --- fluidized bed combustion, coal gas, coal/oil slurry, etc. --- is yet comparable to oil or gas in cost. Moreover, coal is 900 to 1,250 miles away from California and the transport must be added to the cost. New coal-fired boilers with the pollution controls required in California, are not an attractive investment.

UTILITIES (Continued)

Fuel Adjustment Clauses were explained by Lowell Rush of Ernst & Ernst. The present fuel adjustment clause was designed to meet the increases in gas and oil prices, and is not the best for coal. Three things are needed:

- (1) The fuel adjustment clause should be rewritten, tailored specifically to coal use.
- (2) Utilities must set up good practice and documentation. They must plan for both long and short term; select vendors carefully; write good contracts; and monitor both quality and quantity. Transport is extremely important because it is an unusually high percentage of the cost of coal.
- (3) The Public Utilities Commission should set up a system of monthly review, and should allow rate adjustments to go into effect, subject to refund later. This procedure gives the utilities fast relief, but protects the ratepayer against mistakes.

FINANCING

Financing Capital Requirements was discussed by the Bank of America's Edward Vickers. The cost of new ventures such as a coal gasification plant is so huge, and the risks are so great, that financing is a big problem. Commercial banks can lend to utilities on the company's balance sheet, and with the knowledge that the ratepayers will buy the power. But banks cannot lend on a new long-term project which may (or may not) work out, for which there is not an assured market, and which will not be able to pay back for some 10 or 15 years. It may take a consortium or joint effort of several companies, to finance these projects. Loans will be made against the project instead of to the company. The industry concerned should put up 25 to 30% of the money needed, and get the rest from insurance companies or pension funds, perhaps with some of the loans guaranteed by the Government.

COAL POLICY PROJECT

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At an extra evening session, Larry Moss of the Sierra Club and Jerry Decker of Dow Chemical gave a joint presentation on the National Coal Policy Project. This was a mutual undertaking by industry and environmental groups to study problems of coal use, with cooperation rather than an adversary relationship.

The method followed may be more important than the actual report. All pertinent facts were shared; motives were not impugned; a distinction was made between facts and value judgments; there were no sharp tricks; they aimed at a consensus instead of a majority opinion. Government personnel were observers or served as resource people, but the work was done by individuals from industry and environmental associations.

They agreed on several things: that coal can be mined without unacceptable long-term environmental damage in many areas of the U.S. Acid mine drainage was termed "perhaps worse than nuclear waste" because it cannot just be isolated: it must be constantly treated. On air pollution, they could not agree. Industry felt that if air quality standards were met, BACT should not be required; that it would be just an unnecessary expense. Environmentalists felt BACT should be used everywhere, to preclude the chance of a problem later.

The report may be obtained from Center for Strategic & International Studies, Georgetown U, Washington D.C.

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SUMMARY

The California Energy Commission and the US Department of Energy deserve praise for sponsoring the conference on Coal Use for California. As far as we know, this was the first state wide effort to come to grips with a state coal policy. Given the recent debate over energy policy, particularly the availability of coal plants as alternatives to the Sundesert nuclear plant, the conference was very timely. While the conference did serve to stimulate debate, it unfortunately was somewhat less than effective in identifying the major issues associated with increased coal utilization.

From our perspective, the conference would have to be termed disappointing. The most glaring weakness was the tacit agreement among the conference organizers that increased coal use for California is an option that the state should pursue. This underlying theme was very evident by the composition and content of the panels and the participants. In fact, there was not one panel participant that spoke in favor of not using more coal for the state. Certainly the option to forego coal is one that should be considered.

The conference lacked representation from groups that will play a major role in determining the extent of coal use for California. For example, the conference would have been more useful if it included representatives from the Department of Interior, the Forest Service, Native Americans, organized labor, and farmers. These agencies and constituencies

clearly could effect any plans for increased coal use: Forest Service RARE II and BLM wilderness reviews could effectively preempt certain coal development by restricting right-of-ways; Interior could limit coal supply options through its capacity to issue coal leases; Interior's control over water allocation could stifle development; and Native Americans could exercise claims on water, limit transmission corridors, and institute air quality and land use constraints which could preclude certain developments.

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AIR QUALITY ISSUES

A number of speakers at the conference properly pointed out that air quality related issues will likely be one of the key limiting factors in using more coal. We agree, and the Commissions proceedings in AZ 1952 and the PG&E Combined Cycle plant highlight the important role air quality regulations will play in siting new coal plants.

Some of the key air issues will be:

Prevention of Significant Deterioration of Air Quality (PSD)

The PSD provisions in the Clean Air Act were so controversial that in 1976 they were the target of a Senate filibuster which killed the Amendments to the Clean Air Act on the last day of the legislative session. In 1977, however, the overwhelming sentiment in favor of PSD prevailed, hence, Part C to Title I of the Clean Air Act.

Congress adopted a policy to prevent significant deterioration to, among other things:

- 1) preserve, protect, and enhance the air quality of special national and regional scenic, recreational, and historic resources.
- 2) insure that existing areas of good air quality are not sacrificed for economic growth.
- 3) reduce competition among states for new industry.
- 4) assure that interstate pollution does not jeopardize the desire of a state to maintain excellent air quality levels.

Congress mandated strict protection of national scenic treasures, such as national parks and wilderness areas, as a national goal. Limited discretion was given to the states

with respect to the national goal.

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All national parks and wilderness areas were classified as "Class I" which allows very little incremental pollution above the baseline pollution levels. The Class I designation is not subject to reclassification by the state.

Other scenic areas such as national monuments, national recreation areas, and primitive areas are given protection against air quality degradation, but allowable pollution increases are greater and the states are given more discretion in classifying these lands. These lands are classified as Class II and the state may redesignate them up to Class I but it is prohibited from redesignating them to Class III.

All lands that are not mentioned explicitly in the Act can be redesignated to Class III. Class III allows pollution concentrations up to approximately 50-percent of the National Ambient Air Quality Standards (NAAQS). A redesignation to Class III can occur if it is approved by the Governor of the State, if the people in the area to be redesignated are in favor of it, and if it will not cause or contribute to violations of PSD increments or ambient standards in neighboring areas.

According to the Air Resources Board and the EPA, all areas of California except for Los Angeles and Kern counties are meeting the NAAQS for sulphur dioxide--they have "attainment" status. Therefore, almost all sites for coal plants within the state will have to pay particular attention to PSD. This should pose no unreasonable siting difficulties. Joint EPA-SBA studies conclusively have shown that the siting of coal plants would not be significantly effected by PSD as long

as utilities and regulatory agencies avoided areas where there would be plume intrusion on high terrain, the facility uses best available control technologies, and that care was taken in avoiding Class I areas. The House Interstate and Foreign Commerce Committee concluded that up to 6,000 Megawatts of coal capacity could be accommodated in a Class II area.

The impacts of PSD on the siting of out of state plants should also pose few problems as long as care is taken to avoid high terrain and Class I areas. Friends of the Earth would like to discourage the use of out of state plants to avoid the confrontations which have characterized the attempts of California utilities to go out of state in the past. Furthermore, we would be strongly opposed to any sites that require a variance from the Class I increments under section 165 (D) of the Clean Air Act.

Friends of the Earth is a strong supporter of the PSD policy. Furthermore, we think that areas of scenic importance within California such as national recreation areas, national monuments, BLM primitive areas, national and state wild and scenic rivers, national seashores, and state parks should be reclassified as Class I to protect them against air quality degradation.

The most sensible strategy for siting coal plants in attainment areas (other than not doing it at all) is to insure that they use control technologies which will result in the lowest possible emission rates. This will have many benefits-- protection of public health, reducing visibility impacts, minimizing losses in agricultural productivity, and from a

siting standpoint, it will assure that the smallest possible slice of the PSD increment is used, thereby maintaining the greatest opportunity for future industrial development in the same area.

The present PSD policy only applies to sulphur dioxide and particulates. By 1979, EPA could promulgate PSD regulations controlling hydrocarbons, carbon monoxide, oxidants, and nitrogen oxides. To reduce possible conflicts with future regulatory controls, we feel it would be prudent that the state take measures to reduce the above pollutants to the greatest degree possible from any new coal plants in-state.

Visibility Protection

The Visibility Protection provisions of the Clean Air Act add another layer of protection against air quality degradation for areas of national scenic importance. Congress established as a national goal, "the prevention of any future, and the remedying of any existing, impairment of visibility" in national parks and wilderness areas. (42 USC §7479)

The Federal Land Manager of a Class I area (the Secretary of Interior for national park units, and the Secretary of Agriculture for Class I areas on National Forest lands, respectively) has an affirmative responsibility to assure that visibility impairment is avoided.

In carrying out that responsibility, the Federal Land Manager must evaluate the impacts of any new major polluting facility which could adversely effect the visibility of a Class

I area. If he decides that the new facility would cause an unacceptable impairment of visibility, the proposed new source could be prevented from obtaining the permits required to build the project. In case of doubt, the Federal Land Manager is supposed to protect visibility. In addition to preventing new impairment of visibility, the Federal Land Manager, in conjunction with EPA and the states, is required to take steps towards improving any existing visibility problems of Class I areas.

The first step in implementing the visibility protection program was the identification of those Class I areas where visibility is an important value. The Department of Interior has initially determined that 155 out of 158 Class I areas (29,352,311 acres in 38 states) qualify. Thus, unless changed the 155 designated Class I areas will be subject to the provisions under section 169A. By August 1978, EPA in consultation with the Department of Interior, must make a final determination on which areas have visibility as an important value.

By August 1979 EPA must promulgate regulations which will assure that reasonable progress will be made in meeting visibility goals. All states which contain mandatory Class I areas, states with existing polluting sources, and states that might contain sources which contribute to visibility impairment, will adopt strategies in their SIP's by May 1980, in compliance with EPA regulations.

At a minimum, the SIPs will have to stipulate that:

- 1) All major polluting sources in existence less than 15 years

which contribute to visibility impairment of Class I-areas will have to install the "best available retrofit technology" to reduce those emissions which cause visibility problems. The equipment will have to be installed within five (5) years after the SIP revisions are approved by EPA (or five years after EPA promulgates its own SIP revisions for the state). The states will be responsible for determining "best available retrofit technology" taking into account the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. EPA, however, will make the determination of "best available retrofit technology" for fossil-fueled power plants with a generating capacity exceeding 750 megawatts.

2) A long-term (10-15 years) strategy for repairing visibility damage and preventing future degradation will be implemented. The long-term programs will likely require that affected states use careful judgement in selecting specific technologies and sites for future industrial expansion to insure that visibility goals are not jeopardized. **REPRODUCIBILITY OF THE ORIGINAL PAGE IS POOR**

There will be some areas of controversy in achieving the goals mandated in the Visibility Protection section of the Act. For example: determining "best available retrofit technology", predicting effects on visibility from new sources and predicting improvements in visibility from retrofitting; determining whether Visibility Protection applies to vistas outside of Class I areas; evaluating long range transport of pollutants

that cause visibility impairment; limiting industrial siting; and determining visibility impairment in complex terrain.

As with PSD, if care is taken, the visibility protection provisions of the Clean Air Act should not pose inordinate siting difficulties if new coal plants are to be built.

Non-Attainment

The siting of new coal plants in non-attainment areas, those areas that exceed federal ambient air quality standards, is probably the most difficult air quality issue related to increased use of coal in California. Many of the important questions and problems will have to await the promulgation of federal regulations under 40 CFR 51.18 and the state's revised State Implementation Plan due January 1979.

For the sake of argument, and because present non-attainment rules are likely to remain substantially unchanged, I will assume that a new coal plant will have to meet current conditions under the non-attainment regulations.

A new coal plant in a non-attainment area would have to receive a new source permit before construction could begin. Before receiving a permit, the facility must meet certain conditions. The applicant must demonstrate that:

- 1) Reductions in emissions from existing sources will be greater than those predicted from the coal plant. Such "emission offsets", or tradeoffs must be enforceable and they must be completed before the coal plant could begin operation.
- 2) The proposed tradeoffs will result in a "net air quality benefit" in the effected area.

- 3) The coal plant will use control equipment which will result in the "lowest achievable emission rate" for all pollutants in the area which exceeds federal ambient standards.
- 4) All facilities owned or operated in the state by the applicant must be meeting, or be on an explicit compliance schedule to meet all standards and applicable emission limitations under the Clean Air Act.

Friends of the Earth supports the state and federal non-attainment policy. We are concerned, however, that the trade-offs do indeed reduce pollution greater than that put out by new facilities. The de facto 1.2-1.0 ratio used by ARB and EPA does give a regulatory agency a 20-percent margin of error, but this may not be a large enough ratio to assure that actual reductions in ambient concentrations occur and it may not be sufficient to improve the serious problems in the Los Angeles area.

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The requirement for "net air quality benefit" in the effected area is one of some controversy. It is particularly important in areas which have violations of the federal oxidant standards and few indigenous sources of pollution. These conditions occur in many parts of the state and as AB 1852 showed, are particularly important with respect to siting new coal plants in the southern California desert areas. It is doubtful that legally acceptable tradeoffs can be found in the desert for large coal plants given the lack of local air pollution sources since no net air quality benefit in the area could be demonstrated and since interregional trades are likely

illegal.

It may be possible in the future to use interregional tradeoffs to circumvent the problems posed by the non-attainment policy. Reductions in oxidant precursors in say the Los Angeles area could effectively reduce oxidant concentrations in the desert. Friends of the Earth is not opposed to interregional tradeoffs if it can be demonstrated that reductions in precursors from producing areas would decrease oxidant concentrations in areas proposed for new coal plants. Such a determination would require extensive air quality monitoring and a much better understanding of the peculiar atmospheric chemistry involved in oxidant formation and transportation.

If coal plants are to be located in non-attainment areas, the Air Resources Board in conjunction with the Energy Commission should concentrate on those technologies which minimize emissions of nitrogen oxides and hydrocarbons, the primary constituents of photochemical oxidants, since oxidant tradeoffs are likely to be the most important limiting factor in successful siting.

Friends of the Earth is very concerned about potential changes in the state and local regulatory role proposed by the Commission in AB 1852. For example, the Commission proposed that ARB be prohibited from requiring stricter air quality standards than those imposed by EPA. Similarly, local air pollution agencies would be reduced to paper tigers by limiting their permitting authority. These extraordinary measures proposed run counter to the spirit and intent of the Clean Air Act--that state's have "primary responsibility" for

implementing and enforcing clean air programs.

The Commission's proposal in AB 1852 to give the utility industry the highest priority in obtaining air pollution tradeoffs is likely to encounter heated opposition from other industries. There is only a limited potential for obtaining offsets at reasonable prices. Industries other than the electric utilities will require offsets. For example, new petroleum storage, transfer, production, and refining facilities will likely require some tradeoffs. It is therefore reasonable to assume that industries other than the utilities will not be at a competitive disadvantage for limited offsets without a fight.

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Coal Supply

Friends of the Earth maintains a great interest in where (if anywhere) coal will be mined and how it will be delivered to California markets. The most likely candidates are located in the Southwest. These include coal fields in Arizona, Utah, New Mexico, Colorado, and southwest Wyoming.

The key to what coal would be used depends in large part on the capital investment requirements, annualized capital costs, operating costs, and the total annual delivering costs of using coal from a particular coal field.

A 1977 study headed by UCLA for the California Department of Water Resources, the "Study of Alternative Locations of Coal-Fired Power Plants to Supply Energy from Western Coal to the Department of Water Resources," gave some indication where coal is most likely to come from if it is used in California. The study evaluated the costs of importing coal from different locations to supply a 1000 megawatt plant at various sites in-state. The twenty lowest cost scenarios identified by the study are listed in Table I.

A more aggressive coal policy for California would necessitate greater coal imports. A study prepared for the Lake Powell Research Project, "Costs of Transporting Coal from the Kaiparowits Plateau to Southern California," evaluated the costs of importing 10 million tons a year of coal (enough for approximately 3,000 megawatts) to various locations in California. The findings from the report are listed in Table II.

Friends of the Earth has consistently taken a strong position against the development of coal resources in environmentally sensitive areas. We continue to be opposed to such development and hope that the state will make every effort to forego coal development which would compromise environmental values.

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Table 1
The 20 Lowest-Cost Scenarios

Rank	Coalfield	Plant Site	Coal Transportation Mode	Electric Transportation Mode	Cost (mills/kWh)
1	Gallup	Barstow	Rail	a.c.	17.8
2	Alton	Barstow	Pipe	a.c.	18.1
3	Gallup	Goffs	Rail	a.c.	18.3
4	Black Mesa	Barstow	Pipe	a.c.	18.4
5	Gallup	Cadiz	Rail	a.c.	18.4
6	Star Lake	Barstow	Rail	a.c.	18.5
7	Alton	Goffs	Pipe	a.c.	18.6
8	Gallup	Rice	Rail	a.c.	18.6
9	Hanna	Barstow	Rail	a.c.	18.6
10	Yampa	Barstow	Rail	a.c.	18.7
11	Black Mesa	Goffs	Pipe	a.c.	18.7
12	Kemmerer	Barstow	Rail	a.c.	18.7
13	Alton	Cadiz	Pipe	a.c.	18.9
14	Gallup	Parker Valley	Rail	a.c.	18.8
15	Black Mesa	Rice	Pipe	a.c.	18.9
16	Alton	Rice	Pipe	a.c.	18.9
17	Black Mesa	Parker Valley	Pipe	a.c.	18.9
18	Black Mesa	Cadiz	Pipe	a.c.	18.9
19	Star Lake	Goffs	Rail	a.c.	19.0
20	Rock Springs	Barstow	Rail	a.c.	19.0

Table 2: Rail Transportation Costs, Various Coal Sources, to Southern California

Coal Source	Coal Heating Value (Btu per pound)	Narstow		Cads		Dlythe				
		Dr (miles) ^a	Cost (millions of dollars per year) (cents per million Btu)	Dr (miles) ^a	Cost (millions of dollars per year) (cents per million Btu)	Dr (miles) ^a	Cost (millions of dollars per year) (cents per million Btu)			
Kaiparowits ^d	12,000	704	101.9	42.5	807	105.4	45.6	911	116.9	48.7
Bunk Cliffs	12,800 ^e	703	64.9	25.4	801	72.0	28.1	905	80.6	31.5
Star Inake	9,500 ^f	710	65.4	34.4	606	57.9	30.5	710	66.5	35.0
Kramerer	9,700 ^g	883	77.9	40.2	981	85.0	42.8	1,085	93.6	44.3
Grand Hugback and Carbondale	12,000	947 ^h	81.3	34.7	1,045 ^h	90.4	37.7	1,149 ^h	99.7	41.6

^aDr. . . . new 5-mile spur from main line to powerplant site and, for all sources except Kaiparowits, Grand Hugback, and Carbondale, a new 10-mile spur from coal source to main line.

^bAssumes new 17-mile spur from main line to powerplant site.

^cAssumes new 15-mile spur from coal source to main line.

^dRoute 23

^eReference 43

^fReference 44

^gReference 45

^hReference 46

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CONCLUSION

Friends of the Earth neither supports or opposes the use of coal for California. We do feel that the state must learn to live within its "energy budget"--that energy, sun, wind, and biomass, which is renewable. The state should make every effort to level off its energy growth, even promote negative energy growth rates, and promote the fastest possible transition to "soft" technologies.

There is a role for coal to play in the transition to renewable energy resources. Coal can also help to reduce our dependence on less abundant fossile fuels. But, to what extent does the state want to use coal, in what ways (direct firing, production of synthetics, in centralized or decentralized facilities) should it be used, and what are the difficulties in achieving the state's coal use goals? Unfortunately, the conference did little to help resolve these questions.

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**REPORT ON THE JPL CONFERENCE
ON COAL USE IN CALIFORNIA
9-11 May 1978**

**Submitted
to the
California Energy Commission**

**by Laura King
Wayne Hoffman
Natural Resources Defense
Council, Inc.
9 June 1978**

I. Reaction to the Coal Conference

A. Value of the Conference to the State

The main value of the conference was in the broad overview it provided decision-makers in government and industry of the possibilities for coal-based energy in California. Unfortunately, the basically "pro-coal" character of the conference detracted greatly from its value. More appropriate would have been an open, uninhibited evaluation of the desirability of coal vis-a-vis other energy alternatives. Aside from this important shortcoming, the conference was valuable in the following respects.

The presence of federal and state officials from agencies concerned with energy, air quality, and water quality was useful. The mixture of industry, government, and independent research representation was also valuable in that it assured a broad, if at times conflicting, perspective. Perhaps the greatest benefit of the conference was the extensive information provided on present day coal technology. Results from studies on the potential and cost of emission control alternatives were presented. Analyses of cost comparisons with oil, natural gas, coal gasification, and liquefaction were also informative.

The conference was particularly useful in that it identified several important issues yet to be resolved if coal is to become a major energy source in California. One of these is the desire of neighboring coal-producing states that California help pay the environmental and social costs of supplying the

coal it uses. Another is the coordination of timing of coal field development and rail capacity with demand. Others include the effects of the Clean Air Act, oil and gas availability, the expanded use of solar power, implementation of conservation, and the future of nuclear power.

As suggested above, the main weakness of the conference was that it seemed to be premised on the assumption that coal use in California is desirable. Such a conclusion is only valid, however, after a hard look has been taken at the environmental impacts of coal and a thorough analysis of the availability of alternatives has been made. In contrast with the extensive coverage of coal technologies and economics, the conference barely touched on these subjects. For example, the discussions of technologies for coal gasification and liquefaction failed to provide adequate estimates of possible air and water quality impacts, and questions raised by members of the audience on these subjects were not answered. Technology discussion centered on air quality control, with the implication that the most significant obstacle to development of coal is compliance with air quality standards. The discussions of costs associated with coal technology were also deficient in that they avoided comparisons with alternatives such as solar energy and conservation. Moreover, coal cost estimates made relative to oil, gas, or nuclear power did not reflect some relevant environmental costs such as increased health effects to sensitive individuals or social impacts.

The omission of such considerations significantly diminished the value of the conference to the state. Much more valuable would have been an analysis of the alternatives and a cautious assessment of the options for coal use, rather than its wholehearted promotion.

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B. Effectiveness of the Conference in Identifying Major Issues Associated with Coal Utilization

As outlined in the previous discussion, the conference orientation was towards existing and probable technologies in the field. Thus, it was most effective in identifying issues related to their utilization. These include systems efficiencies, systems costs, and ability of systems to meet the requirements of the clean air laws. For example, the effectiveness and cost of flue gas desulfurization, scrubbers, and electro-static precipitators were discussed in detail.

Other issues identified by the conference include views of neighboring states, problems with water availability, cost of coal relative to other existing energy sources, transportation availability, and capital financing requirements. While these issues are all important considerations once it is decided to go ahead with coal, the conference did a poor job of identifying the issues which should be reviewed before the decision to use coal is made. Particularly important is analysis of environmental impacts and alternative energy sources. Although the conference acknowledged the issue of environmental impacts, it was mainly from the perspective of regulatory restraints on coal development imposed by the air quality standards. It provided little perspective at all on the issues surrounding development of alternative energy sources.

Examples of topics which were not covered by the conference include:

- health effects of coal combustion products
- socioeconomic effects of coal development
- degradation of Class II and Class III air quality
- water impacts of synfuel production
- climatic effects of increasing carbon dioxide levels
- cost of coal relative to cost of conservation and solar, wind and geothermal energy
- comparison of environmental impacts of coal fuel cycle with those of alternative energy sources
- comparison of environmental impacts of different coal fuel cycles, e.g., between electricity from direct combustion and production of syngas.

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C. Adequacy of Coverage of the Major Topics

The quality of the conference's coverage of the major issues associated with coal use in California was varied. The conference was strongest in its presentation of information regarding the technological possibilities for coal use and for emissions controls. The viewpoints of the coal-producing states were also well-represented. The area of weakest coverage was that of environmental impacts of coal use, particularly of the new technologies for coal conversion. Also inadequate was the discussion of California's need for energy, and there was little mention of the ways other than coal that California's needs can be met.

The issue receiving the best coverage was the mitigation of air pollution from coal combustion. The discussion of air pollution control technologies was particularly useful in that more than one point of view was represented. For example, the report by Tom Austin of the Air Resources Board on Japanese nitrogen oxide control systems was supplemented by a talk by Don Teixeira of EPRI, in which a somewhat less sanguine view was presented on their status.

Coverage of other air pollution control technologies was also extensive. In addition to control of nitrous oxides, several systems for control of sulfur oxides and particulate emissions were reviewed. Many of the talks included useful information on the costs of the systems and their relative share of the total cost of energy produced from coal. The only weakness of the overall discussion of air pollution control technology was that, with the exception of the NOx controls,

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it tended to emphasize the capabilities of the various systems. Potential problems, such as life expectancy, replacement cost and back-up systems, were minimized.

The sessions on coal technology -- direct firing, gasification and liquefaction -- were informative at a level as detailed and technical as is possible in a conference format. The viewpoints and work of the utilities, federal government and coal industry were well-represented. Since most of these speakers have a vested interest in the technologies, however, the perspective again tended to be promotional. A more objective analysis of the potential of the technologies might have been provided by the inclusion of several speakers such as university professors or independent researchers.

In the area of economics, the most important issue is the total cost of coal relative to that of other sources of energy. Certain aspects of this subject were covered in some detail by Charles Mann in his talk entitled, "Life-Cycle Costs of Utilizing Coal in California." Mann correctly pointed out that there is some dispute as to the difference between the cost of electricity produced by coal and nuclear-generated electricity. However, Mann omitted comparison of coal generation costs with those of electricity generated by means other than nuclear, such as conventional oil-fired plants, combined cycle oil-fired plants, combined cycle plants with the ability to convert to synthetic gas produced from coal, and cogeneration using natural gas or oil. Neither did Mann discuss the economics of some of the other newer coal technologies, and since most of the talks on the technologies themselves made only brief mention of costs,

this area was somewhat lacking in coverage. (Since many of the technologies are only now emerging, the cost estimates would be somewhat speculative at this point; nevertheless, it would be worthwhile to have a relative idea of what the costs may be.)

The most important failing of the entire session on economics was that it did not discuss the economics of any of the alternatives to traditional fuel sources, e.g., conservation, solar energy, wind power, and geothermal. Nor did it deal with decentralized applications of coal. Since many of the existing demands for electricity and energy could be met or decreased by conservation and the less traditional sources of energy, it is important to compare coal costs with those of all other forms of energy, not just with those fuels which are currently used.

The conference's coverage of the issue of demand for both electricity and other forms of energy was disappointingly general. The most thoughtful speaker on this subject was Mike Jones, who provided statistics on growth rates projected by the utilities and the Energy Commission. Jones' talk could have been more helpful, however, in two respects. First, he could have provided a quantification of the potential impact of conservation upon demand. (While conservation was mentioned, he did not give a value for its impact on the projected growth rate.) Second, a useful perspective would have been provided by information regarding what kinds of electrical capacity expansion would be required under the various assumed growth rates. This omission was both representative of and contributory towards

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a major problem of the entire conference, namely that it did not take a hard look at what kind of demand the state might have for coal or at the alternative ways in which that demand might be met.

It is hard to imagine serious consideration of coal use in California without a thorough analysis of the alternative energy sources, both traditional and untraditional, available to the state. Nevertheless, the conference was conducted without a single session on this subject. The assumptions underlying the exclusion of such an analysis were laid out well by Governor Brown in his opening talk: 1) state growth is going to continue, along with a concomitant increase in energy use; 2) coal is probably cheaper than nuclear power for producing electricity; 3) California needs to diversify its energy supply mix as much as possible; and therefore, 4) California needs coal. The fourth conclusion assumes the absence of other alternatives, however -- a notion the conference did little to dispel. While a number of speakers mentioned solar and conservation as means for reducing demand, there was no concrete analysis of the potential of these and other alternatives and of how it might affect the need to rely on coal in California.

The coverage of the conference on environmental impacts of coal use was little better than token. As Dwight Carey of the Sierra Club pointed out, the importance of environmental issues to the organizers of the coal conference was reflected in the fact that only one out of the twelve sessions was devoted to the subject. Even more disturbing was the apparent confusion of environmental impacts with regulatory constraints upon coal

development. For example, two of the three panelists in the session on environmental aspects of coal use were representatives of regulatory agencies, not environmentalists. While both speakers, Tom Austin and Ronald Robie, have excellent records of protecting the environment through enforcement of the law, the thrust of their remarks was whether the use of coal would violate environmental laws. As Austin admitted, even if a coal-fired electric power plant complied with air quality laws, some emissions of pollutants would occur. However, his talk avoided discussion of this issue, and it was not treated in detail by any of the other speakers at the conference.

The issue of water impacts of coal development was similarly inadequately treated. The main emphasis of Robie's talk was the supply of cooling water as a constraint to coal-fired power plants, and the information he presented was limited and general. There are a number of other important issues relevant to water which should have been discussed. One is the increasing salinity of the Salton Sea, a problem which will be exacerbated by the evaporation of water used in power plant cooling. Another is the water requirement of reclamation of stripmined lands. Also important is the issue of water supply for and water quality impacts of coal synfuel production.

Each of these issues or their combination represents a potential constraint to the use of coal in California, as is reflected by the titles of two of the talks in Session III. However, none of the talks made an attempt to quantify precisely how limiting those constraints might be. Such an omission is significant, because as long as coal is considered only in

generalities, many of the issues which may actually stand in the way of its development can be sidestepped. A particularly apt example is local attitudes towards specific coal projects.

General coverage of environmental impacts associated with coal use in California could perhaps have been improved by including a discussion of environmental impacts as part of the specific topics in each session. For example, the talk on using coal inside California for electric power could have included or been accompanied by an overview of the environmental impacts of coal-fired electric power plants. Similarly, the discussions of the coal technologies -- direct firing, gasification, and liquefaction -- could have incorporated detailed information on the environmental impacts associated with their development. Some of this information could be available from the industry speakers, although outside sources of information from environmentalists, professors and independent researchers would provide a more objective balance. (A case in point was the discussion of the water impacts of coal slurry lines, in which the industry speaker's optimistic view was challenged by a member of the audience.)

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D. Overall Balance of the Conference

As expressed in the preceding remarks, the conference was poorly balanced in that it was heavily oriented toward coal development, rather than investigating the pros and cons of coal use in California. The serious environmental and sociological ramifications of such development were at best glossed over and often ignored.

In general, the public's interests were not represented. Most of the speakers and members of the audience were from industry or research groups responsive to the needs of industry. Representation of the public was confined to a handful of environmentalists, regulators, politicians and utility managers. While some of these groups represents a part of the public interest, additional representation from that portion of the public not directly involved in the energy policy arena would have been desirable. The few members of the general public who attempted to speak at the conference indicated that it did not address their concerns. More importantly, their views were given only minimal response by the moderators and panelists.

In conclusion, our main criticism of the conference is of its a priori assumption that coal use in California is necessary and desirable. As discussed below, we disagree with the assumption that it is necessary. Furthermore, a more balanced discussion of its use would have resulted in serious questions as to its desirability.

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II. Position on Increased Coal Utilization

NRDC and its constituency do not have a formal position for or against increased coal utilization in California. These remarks are therefore limited to a general discussion of our concerns regarding coal use.

A. Positive Impacts of Coal Use

The primary positive impact of coal use is that it is a source of energy, an economic good which contributes to the welfare of society. Since other fuel sources are also available to provide energy, the benefits of coal use must be viewed in relation to the impacts of reliance on other supply sources. Perhaps coal's greatest advantage is that the domestic coal resource is substantial, so that increasing its use relative to oil consumption will reduce our reliance on imports of oil and make our economy less vulnerable to fluctuations in world oil prices. Another potential benefit of coal use is that coal-fired electricity appears to be cheaper than electricity produced in power plants fueled by oil or uranium. A third positive feature of coal use is that it can be used in a variety of applications: in facilities both large and small, centralized and decentralized. Thus, if its use is planned wisely, it could serve as a transitional fuel to an energy supply mix based more heavily on renewable energy resources.

3. Negative Impacts of Coal Use

From our perspective, the list of negative impacts of coal use is considerably longer than that of positive impacts.

Although many of the environmental impacts of coal development will occur outside California, we believe that consideration must be given to impacts of the entire coal fuel cycle. Mention has been made of most of these impacts in the above evaluation of the conference. We are most concerned about the following areas:

1. Land and water impacts of coal mining operations -- Stripmining coal will result in tremendous disturbance of the surface of the land. Reclamation of land in arid parts of the West is expected to require large amounts of water, and there is much uncertainty as to whether reclamation can be successful even if the necessary water is available. Underground mines will also be associated with some disturbance of the surface, if only to the extent that roads and facilities for workers will be constructed in hitherto deserted areas. Preparation of coal at the mine site will consume large volumes of water, and some provision will be required for residual disposal.

2. Land impacts of rail transport -- Transport of coal to California may require the construction of many new railroad lines, involving habitat disturbance and destruction over thousands of miles.

3. Water impacts of slurry transport -- If coal is to be transported by slurry rather than by rail, large volumes of water will be consumed. Heavy demands are already being placed upon the West's water supplies, putting a strain on natural aquatic ecosystems. The loss of more water in slurries will increase the strain, as will the return of water contaminated by the slurry to natural water bodies.

4. Water impacts of coal conversion -- If coal is to be used as liquid or gas, its conversion to these forms will consume and contaminate large amounts of water, again exacerbating the problems described above. Conversion of coal to electricity may also result in large evaporative losses of water due to cooling requirements. Alternatively, the discharge of cooling water directly into rivers and lakes may cause thermal pollution.

5. Air impacts of coal conversion -- Even if emissions from coal combustion are within federal and state limits, some adverse aesthetic impacts will occur, as will increased health risks. Of special concern is the health effect of fine particulates, emissions of which are not prohibited under current air quality standards.

6. Land and water impacts of sludge disposal -- The treatment of coal for direct combustion and the conversion of coal to other fuels will both create large volumes of sludge, which must be disposed of on land or discharged into water. Neither of these alternatives is attractive environmentally.

7. Climatic effects of increased carbon dioxide levels -- Perhaps the ultimate limit to full utilization of the coal resource is the potential impact on global climate of increasing CO₂ levels resulting from fossil fuel combustion.

C. Recommendations Regarding Coal Use

In view of this cursory sketch of the potential negative impacts of coal use, we recommend that the state of California attempt to minimize its use to the extent possible. Instead, the state and local governments must actively pursue the develop-

ment of more environmentally acceptable energy sources, including geothermal, biomass, wind and solar. For the long-term, particular emphasis should be placed on developing technologies for use of renewable resources. Since these resources cannot now satisfy California's energy demands, the state must also develop a short-term strategy which encourages the full implementation of conservation potential. The efficiency of current fossil fuel use should also be improved through such things as cogeneration and repowering of existing oil-fired power plants. Only if this strategy is unsuccessful in meeting California's energy needs should the state turn to coal. In that event, it should choose coal applications which are small in scale and which provide maximum protection of the environment.

COAL USE FOR CALIFORNIA:

A Conference Report

prepared by

**Ronald Y. Wada
Association of Bay Area Governments
Berkeley, California**

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for

**California Energy Commission
Sacramento, California**

June, 9, 1978

INTRODUCTION

The purpose of this report is to summarize (1) reactions to the recent conference, "Coal Use In California," sponsored by the California Energy Commission and the U.S. Department of Energy, and (2) ABAG staff's activities on increased coal utilization in the State.

The Association of Bay Area Governments is the voluntary joint powers agency representing over 90 city and county governments in the San Francisco Bay Area. Our primary function is to provide a forum for discussion and policy development by local governments on a broad range of common regional problems, such as housing, economic development, pollution, and health services. ABAG has been designated as the lead agency in the Bay Area for a number of planning programs which would be relevant to coal use in California:

- o Air quality planning, designated by the California Air Resources Board;
- o Water quality planning, designated by the State Water Resources Control Board and the U.S. Environmental Protection Agency;
- o Solid waste management planning, designated by State legislation;
- o Industrial siting process development designated by the State Office of Planning and Research.

With respect to the prospect of coal use in California, and in particular with respect to Pacific Gas and Electric Company's proposed Fossil 1 & 2 units now entered in the Commission's NOI process, a number of specific issues of concern to ABAG are:

- o Under what conditions of siting, emission control, and air quality criteria will new coal fired facilities be allowed to operate in California?
- o Disposal of solid and/or liquid residue from coal combustion, particularly when scrubbers and precipitators are to be used for air pollution control, will likely require Class I disposal sites suitable for hazardous materials. At what rate would such wastes be generated, and would this force identification of additional sites (an unpopular issue with local governments)?
- o What assumptions (e.g., future population) were used in the specific demand forecast which indicated a need for such a facility? How was energy conservation factored into the forecast?
- o What is an appropriate balance of fuel types for satisfying California's energy demand while minimizing resulting environmental problems?
- o How will issues of legal/regulatory jurisdiction be resolved (e.g., Clean Air Act and Mulford-Carrell Act vs. Warren-Alquist Act and Energy Supply and Environmental Coordination Act)?

One basic problem with most of the presentations at the conference was that they did not approach the level of specificity appropriate to address these issues. A great deal of time was devoted to reviewing the state of research and development for various coal technologies and pointing out the variety of potential environmental and other problems associated with each. It seemed as though there were two factions represented: coal project developers on one side, and regulatory agencies and public interests on the other. Both sides stated their positions in their own terms with neither side really hearing the other. This problem was recognized on the first day of the conference when one of the session chairmen remarked that although everyone was hearing the same tune, they were dancing different steps in response. The environmental and regulatory interests pointed to potential problems and unanswered questions, while the utilities and coal developers complained of excessive bureaucratic review. It seemed that both factions indulged in excess rhetoric, in addition to having valid points to make.

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DIRECT FIRING OF COAL

The most constructive and substantive presentation of the conference was made by Tom Austin of the California Air Resources Board. According to Mr Austin, technology currently being demonstrated in Japan can reduce emissions from direct coal combustion (in utility boilers) to levels below that produced by fuel oil and comparable to levels from natural gas-fired boilers. This was later verified by Mr. Don Texeira of the Electric Power Research Institute. Mr. Austin went on to suggest that very stringent New Source Performance Standards (NSPS) for coal-fired facilities would be appropriate for California. This is probably the most crucial and immediate issue regarding direct firing of coal in California.

The Air Quality Maintenance Plan developed by ABAG for the San Francisco Bay Area is currently in its final approval stages. It places substantial reliance on the New Source Review process and its requirement that new sources of air pollution achieve the lowest achievable emissions rate (LAER), as mandated in the 1977 Clean Air Act Amendments. Although no one has as yet defined what LAER is for various sources, Mr. Austin's presentation and suggested NSPS for new coal fired facilities are indicators of the direction in which ARB is headed.

One year ago, in an attempt to gain more insight on the potential of various technologies to reduce emissions from various source classes, ABAG conducted a technology forecast survey. A panel of experts was assembled for each major emission source category, and questionnaires were developed to direct the panelists in an exploration of the potential future of emission control technology. The results of the survey for combustion sources have been summarized in the attached technical memorandum (Attachment I). In general, the survey results suggested that improved control technologies, particularly for NOx, would be commercially available within ten years. Potential control efficiencies expected were somewhat less than that reported by Mr. Austin.

The issue of what constitutes the best available control technology is of immediate relevance to future decisions regarding Pacific Gas and Electric

Company's Fossil 1 & 2. as with coal development in general, timing is a crucial variable. Few people question the wisdom of diversifying California's energy supplies to include coal. The real issue is when and under what conditions.

COAL CONVERSION TO ALTERNATIVE FUELS

Amidst all the discussion of the varying aspects of gasification processes and other forms of coal conversion, not one presentation addressed the question of the realistic fuel production potential as a function of time. It seems likely that at the current pace of development, such processes may contribute to satisfying domestic needs (e.g., home heating) for oil and natural gas, and that substantial production to fuel new power plants or factories lies somewhere in the distant future, if at all. A key factor, the reluctance of the federal government to develop loan guarantees for energy projects, was alluded to, but never directly addressed.

Moreover, one outcome of the conference was that the coal-producing states will not continue down the path of allowing power plants to be constructed near the coal fields and transporting the power out of the state while leaving the pollution behind. This concept could easily be extended to coal conversion processes as well.

Thus, it appears that at least for the near future if coal is to be used in California, it will be by direct firing.

In conclusion, the conference in and of itself was informative, though not particularly productive. As the initial step in a continuing dialogue and process for conflict resolution, it served the purpose of allowing the adversaries to meet and exchange views. To bring this effort to fruition, subsequent conferences or workshops should be centered on specific issues (e.g., air quality regulation and technology) and should be designed around a formal, conflict resolution process.

ATTACHMENT 1.

*Metropolitan
Transportation
Commission*

BAY AREA ASSOCIATION
AIR POLLUTION OF BAY AREA
CONTROL DISTRICT GOVERNMENTS

ENVIRONMENTAL
MANAGEMENT
PROGRAM

AQMP/Tech Memo 10 AIR QUALITY MAINTENANCE PLAN

July 1977

SUMMARY OF RESULTS

TECHNOLOGY FORECAST QUESTIONNAIRE
COMBUSTION SOURCES

The Technology Forecast Questionnaire was designed to determine the impact of future technological developments on combustion source emissions. By polling a panel of experts using the Delphi technique, it was hoped that a consensus opinion could be obtained on a wide range of new and commercially untested technologies that might have significant impacts on the nature of air quality problems in the decades to come. While technological solutions have large public appeal because they involve minimum disruption of established institutions and lifestyles, they often involve long lead times between conceptualization and commercial usage, and they involve very high costs. This survey effort was designed to identify a realistic time frame for when new control techniques would become available in order to gain a perspective on the need for other types of controls. The results of the survey were planned to 1) help define best available control technologies (BACT) by 1985 and 2000 and 2) determine the upper bound of future emissions and air quality estimates.

The first round of questionnaires (originally three were planned) covered the following areas:

- o baseline emissions for five combustion units: commercial boilers, refinery heater, industrial firetube boiler, industrial watertube boiler, utility boiler
- o reduction of SO_x and NO_x and particulate emissions for each of the above units
- o pace of technological development
- o control costs

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The control technologies that were evaluated are listed in Table 1.

While the rate of response to Round 1 was satisfactory -- fifteen mailed back out of eighteen -- few of those surveyed were able to complete more than 25% of the questionnaire. None of the participants were familiar or had expertise in all the controls or in all the types of units. The results of the survey are described in the following section.

TABLE 1

CONTROL TECHNOLOGIES

SO_x

FLUE GAS DESULFURIZATION

- limestone process
- lime process
- magnesia process
- sodium process
- catalytic oxidation

ALTERNATIVE CLEAN FUEL FROM COAL

- low/medium BTU gas
- synthetic oil
- desulfurized coal

DESULFURIZATION OF PETROLEUM

PARTICULATE

- electrostatic precipitator
- mechanical collector
- bag filterhouse
- wet scrubber
- fuel additive
- opacity monitoring/
burner controls

NO_x

COMBUSTION MODIFICATION

- low excess air
- staged combustion
- flue gas recirculation
- reduced air preheat
- burner design modifications

FLUE GAS TREATMENT

- selective catalytic reduction
- selective non-catalytic reduction (ammonia)
- oxidation/scrubbing

ALTERNATE CLEAN FUEL FROM COAL

- low/medium BTU gas
- synthetic oil
- desulfurized coal

FUEL ADDITIVES

- FUEL DENITRIFICATION (pretreatment of fuel to remove nitrogen compounds)

CATALYTIC COMBUSTION

QUESTIONNAIRE RESULTS

The results of the survey are summarized in Attachment A. Respondents were requested to rate themselves as very familiar, moderately familiar or unfamiliar with each control technology. The values of responses show the range of values given by those who indicated that they were moderately or very familiar with the subjects in question.

The following observations were made on the survey results:

- o The wide range of technologies being studied and developed for combustion emissions control is so extensive that it is difficult for a single group or individual to have expertise in all of them. Typically, research efforts concentrate on one aspect of control a particular class of combustion unit, a single pollutant, engineering feasibility, economic feasibility, commercial application, etc.
- o A very wide range of emissions reduction potential were reported (e.g. 20-95% for flue gas desulfurization on desulfurization on utility boilers). This could be attributable to the fact that control efficiencies for new technologies are based on prototype, idealized operating conditions; actual operational performance may vary significantly. Thus, engineers who have experience in implementing new controls tend to be more pessimistic than researchers.
- o Up-to-date cost data are difficult to obtain. Although cost information exists (and was cited by a few of the respondents) in the literature, they are often two, three or more years old or are presented in a variety of non-standardized formats. Some cost information of control equipment is known by manufacturers but are of a proprietary nature.
- o There existed some question as to whether the percentage reductions cited by respondents were applicable to baseline or uncontrolled emissions levels (although the instructions specified reductions over baseline emissions).
- o The wide range of projected control efficiencies indicated that there are considerable operational problems with the proposed technologies and that actual emissions reductions will be lower than those projected by research efforts.
- o Implementation of NO_x controls in new units are considerably less difficult and costly than existing units.
- o Flue gas desulfurization costs appear to have risen 200 to 300 per cent from the last comprehensive and definitive cost study performed by McGlamery and Torstrick in 1975.

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o The technologies which are predicted to be available by 1985 for widespread commercial use are:

- flue gas desulfurization
 - limestone process
 - lime process
 - sodium process

- desulfurization of petroleum to .25% sulfur

- combustion modification
 - staged combustion
 - low excess air
 - flue gas recirculation
 - burner modifications

- flue gas denitrification
 - selective non-catalytic reduction with ammonia

- fuel denitrification

o Additional technologies which are predicted to be available for widespread commercial use by the year 2000 Are:

- alternative clean fuels
 - low/medium BTU gas
 - oil from coal
 - desulfurized coal

- desulfurization of petroleum to .1% sulfur

- flue gas denitrification
 - selected catalytic oxidation

TECHNOLOGY WORKSHOP

In view of the problems encountered with using the questionnaire format, a one-day workshop was convened to discuss further the status of combustion control technology. Participants of the workshop (see Attachment B for attendance list) were asked to review the results of Round I and attempt to narrow the range of response where possible. Their comments and opinions are summarized in attachment A.

Planning Assumptions

Based on Round I results and workshop comments, the following tentative planning assumptions are proposed for the air quality evaluation:

1. Flue gas desulfurization (FGD) processes are able to yield 80% or more reductions of SO_x emissions over uncontrolled levels for utility and large industrial boilers (assuming .5% sulfur content in fuels).

2. Desulfurization of petroleum to .25% sulfur content is commercially feasible now.
3. FGD controls for smaller industrial and commercial boilers are not cost-effective at present levels of fuel prices and supplies. FGD becomes economically attractive when fuel is high in sulfur content and low in price. However non-utility boilers are not equipped to burn dirtier fuels (problems of corrosion, etc.)
4. Combustion modification techniques for reducing NOx emissions from existing industrial and commercial boilers do not appear to be technically or economically feasible. However, 10-20% reductions have been demonstrated through improved maintenance and improved fuel atomization via emulsifiers.
5. Alternate clean fuels appear to be most promising for industrial and commercial boilers which would not be able to switch satisfactorily to dirtier fuels. These technologies appear to become technically and economically feasible in the late 1980's-1990's as low sulfur fuels become scarce and, consequently, more expensive.
6. Flue gas treatment for NOx control appears to be feasible by 2000 only for large industrial and utility boilers. It would yield 50-90% control efficiency, depending on the process.

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ATTACHMENT A - SURVEY RESULTS

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QUESTION 1 **BASELINE
EMISSION
FACTORS**

Emission control technology will be examined for five combustion categories, identified as major sources of NO_x, SO_x and particulate emissions in the Bay Area. These categories are listed below:

MAJOR COMBUSTION CATEGORIES:

Commercial Boiler (for space heating)
Refinery heater
Industrial Boiler-.3-10 mmbtu/hr; firetube
Industrial Boiler-10-250 mmbtu/hr; watertube
Utility Boiler->250 mmbtu/hr

In this question, a baseline emissions level is established for each combustion category in order to provide a base from which to calculate control effectiveness.

INSTRUCTIONS: We would like you to critically review the baseline emission factors and where you disagree, correct them appropriately. These factors represent present emissions characteristics with state-of-the-art controls and current emissions regulations.

SOURCE DESCRIPTION		POLLUTANT ¹		
EQUIPMENT TYPE	FUEL	SO _x (LB/MMBTU)	NO _x (LB/MMBTU)	PARTICULATE (LB/MMBTU)
COMMERCIAL BOILER	GAS		.08	.001
REFINERY HEATER	GAS		.22	.002
	REFINERY GAS ²	.001 <u>.0026-.4</u>	.22 <u>.05</u>	.002 <u>.001-.02</u>
	RESIDUAL ³	.533 <u>.25-.56</u>	.460 <u>.1-.5</u>	.133 <u>.05-.15</u>
	COKE ⁴	1.26 <u>.7-2.0</u>	.72	.18
INDUSTRIAL BOILER-FIREBRICK	DISKINATE RESIDUAL	.523 <u>.25-.56</u>	.40 <u>.1-.2</u>	.153 <u>.01-.06</u>
INDUSTRIAL BOILER-WHITE OIL	RESIDUAL	.523 <u>.25-.56</u>	.70 <u>.25-.5</u>	.153 <u>.05-.2</u>
	COAL ⁵	1.20 <u>1.2</u>	.70 <u>.70</u>	.10 <u>.10</u>
UTILITY BOILER	RESIDUAL	.523 <u>.523</u>	.700 <u>.70</u>	.053 <u>.053</u>
	COAL ⁶	1.20 <u>1.00</u>	.70 <u>.70</u>	.10 <u>.10</u>

1) SOURCE: AP-42

2) .016% SULFUR IN REFINERY GAS, 1095 BTU/CU FT

3) .5% SULFUR IN RESIDUAL OIL; 150,000 BTU/GAL

4) 35 LB SO_x/TON COKE, 20 LB NO_x/TON COKE, 5 LB PART/TON COKE, 1000 MBTU PER 36 TONS COKE

5) NEW SOURCE PERFORMANCE STANDARDS

QUESTION 2 EMISSION REDUCTION POTENTIAL

In this question we assess the potential emissions reduction of a wide range of control technologies for the combustion source categories given in Question 1. The technologies are shown below, along with some specific processes and techniques which appear promising. It is recognized that stationary source control technology for SO_x and NO_x are in varying stages of development with uncertain commercial futures. Thus, combustion and emission characteristics may not have been established on a fully operational scale. In many cases, emissions reduction can only be accurately determined on a case-by-case basis, depending on the particular operating mode of the equipment. Nevertheless, for planning purposes, we again make the same assumptions on combustion equipment as in Question 1 in order to evaluate a control's relative effectiveness.

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INSTRUCTIONS: We would like you to give low and high estimates of emissions reduction potential for the appropriate combinations of technology and source category. Your estimates should be in the form of percent reduction over the baseline emissions developed in Question 1 (as corrected by you). For example, combustion modification techniques can achieve 30-50% reduction in NO_x emissions from utility boilers.

Please also indicate your degree of familiarity with each technology, i.e., very familiar, moderately familiar, unfamiliar. You are encouraged to comment on your estimates, add to the list of technologies or specify promising processes for a technology.

80% EMISSIONS REDUCTION POTENTIAL (%)

FUEL	COKE GAS			COKE			SEMI-SEMI			SEMI			COMMENTS
	COKE	SEMI	SEMI	SEMI	SEMI	SEMI	SEMI	SEMI	SEMI	SEMI	SEMI		
BASELINE EMISSIONS (FILL IN)													
FLUE GAS DESULFURIZATION													Operators prefer cleaning the fuel to cleaning the flue gas.
• LIMESTONE PROCESS											60-95		FG becomes attractive for high-sulfur, low-cost fuels!
• LIME PROCESS											70-95		
• MAGNESIA PROCESS											70-95		
• SODIUM PROCESS											80-90		
• CATALYTIC OXIDATION											0		
PETROLEUM & DESULFURIZATION													
• TO .25 % S											50		
• TO .1 % S											80		
ALTERNATIVE CLEAN FUELS													
• LO/MBD BTU GAS											90	95	There are distribution and retrofit problems
• SYNTHETIC OIL FROM COAL											80		
• DESULFURIZED COAL											10-10	10-15	
OTHER (FILL IN)													

INCLUDE THE BALL OF THE BALLS AND ADDITIONAL COMMENTS.

* 1. VERY
 2. MODERATELY
 3. UNFAMILIAR
 ** R. ASSUME .5% S FRESH STEEL

NOx EMISSIONS REDUCTION POTENTIAL (%)

FUEL	GAS		OTHER GASES		COAL		OIL		COMMENT
	GAS	OTHER GASES	COAL	OTHER GASES	COAL	OTHER GASES	COAL	OTHER GASES	
COMBUSTION MODIFICATION									
• LOW EXCESS AIR									
• SWAGED COMBUSTION									
• FLUE GAS REHEATING									
• SEPERATED AIR PREHEATING									
BURNER DESIGN MODIFICATIONS									
FLUE GAS TREATMENT									
• SELECTIVE CATALYTIC REDUCTION	80-90								
• SELECTIVE NON-CATALYTIC REDUCTION (AMMONIA)	60-90								
• OXIDATION / SCRUBBING									
ALTERNATE CLEAN FUELS									
• LOW/BED BTU GAS	90	90							
• SYNTHETIC OIL FROM COAL									
• DESIGN ENRICHED COAL									
FUEL ADDITIVES									
FUEL DENSIFICATION									
CATALYTIC COMBUSTION									
OTHER (FILL IN)									
• fuel rich emulsions									

Reductions are achieved by the combination of the following gas treatment

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1 - VERY
2 - MODERATELY
3 - UNFAMILIAR

PARTICULATES
EMISSIONS
REDUCTION
POTENTIAL (%)

FUEL	SOLUBLE METALS CONTROL				SOLUBLE METALS CONTROL				SOLUBLE METALS CONTROL				COMMENT OR BASELINE EMISSIONS LEVEL 90% + control
	GAS	FLYASH	COKE	RESIDUAL COKE	RESIDUAL COKE	RESIDUAL COKE	RESIDUAL COKE	RESIDUAL COKE	RESIDUAL COKE	RESIDUAL COKE	RESIDUAL COKE	RESIDUAL COKE	
BASELINE EMISSIONS (FILL IN)													
ELECTROSTATIC PRECIPITATOR										0-30	0-45		
MECHANICAL COLLECTORS										0	0		
BAG FILTERHOUSES										0-60	0-70		bag filter particulate control
WET SCRUBBERS										0-30	0-30		
FUEL ADDITIVES										0-20	0-20		
OPACITY MONITORING/ BURNER CONTROLS										10-20			
VELOCITY CONTROL										10			
OTHER (FILL IN)										30	30		
.													

* USE THE BACK OF THIS PAGE FOR ADDITIONAL COMMENTS

- * 1 - VERY
- 2 - MODERATELY
- 3 - UNEQUALUAR

QUESTION **3** PACE OF
TECHNOLOGICAL
DEVELOPMENT

New technological concepts pass through several stages of research and development before successful commercial applications can be realized. The first is that of scientific feasibility (I) where the concept is experimentally verified. The second is that of engineering feasibility (II) where an operating prototype verifies that a concept will in fact function as intended. The next step of commercial development (III) tests the concept against competitive alternatives and demonstrates economic feasibility. Finally, a technically and economically proven desirable alternative is ready for widespread adoption (IV) to be integrated physically and operationally into the entire system. Typically, the lag time or accession from one stage to another takes many years. Sometimes, scientific discoveries, governmental regulations, new technological insights and changing economic conditions will speed up this process and make feasible, processes which formerly appeared to be infeasible.

INSTRUCTIONS: In this question, we would like you to 1) identify specific and most promising process(es)/technique(s) under each broadly named technology; 2) indicate for each process or technology the stages of development on the time scale provided as follows:

Let II represent engineering feasibility is demonstrated

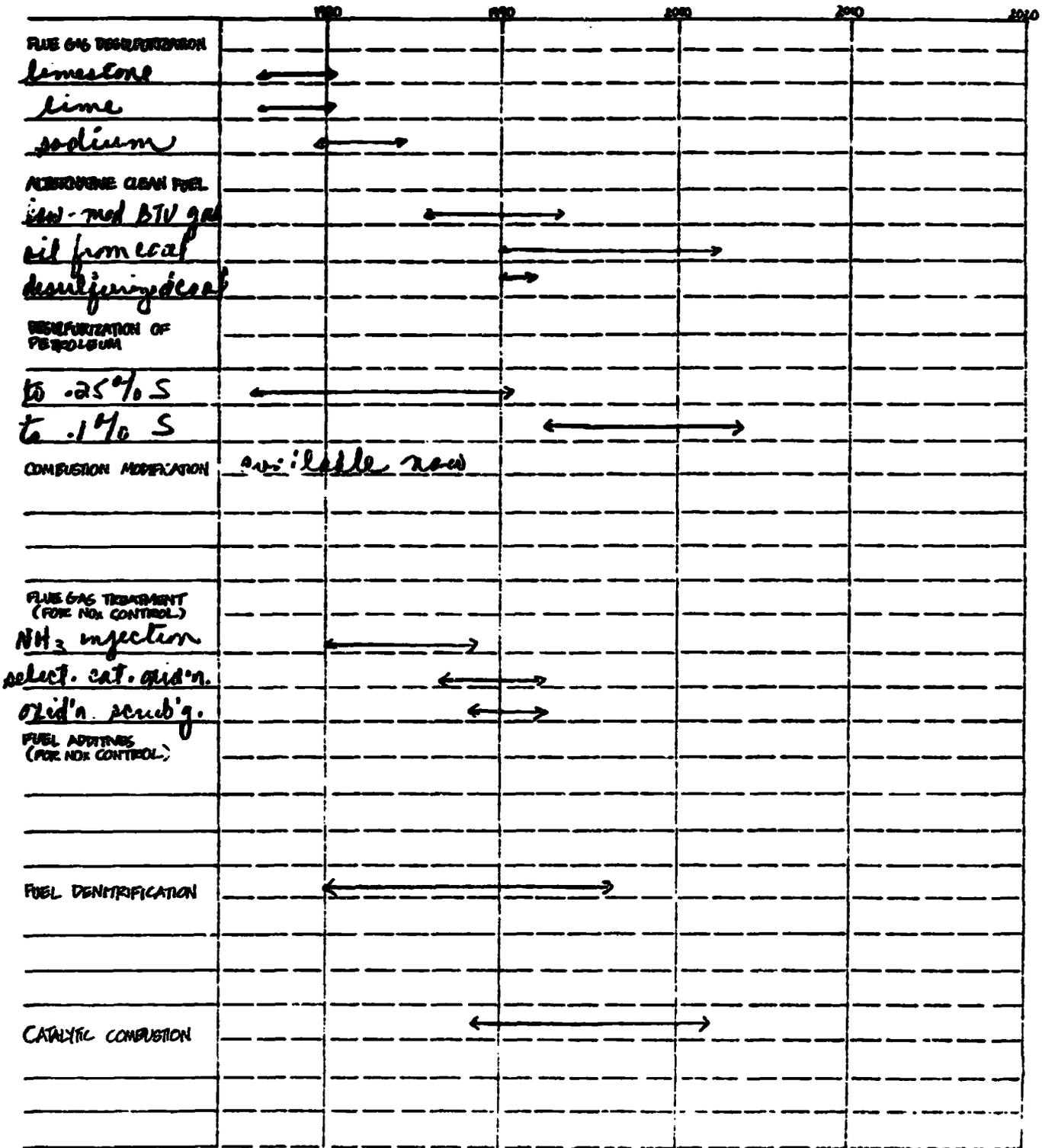
III represent commercial feasibility is demonstrated

IV represent widespread adoption is achieved

It is assumed that the scientific feasibility (Stage I) of all of these processes has been demonstrated.

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FACE OF TECHNOLOGICAL DEVELOPMENT



← → time frame for availability of technology for widespread commercial adoption

QUESTION **4** CONTROL
TECHNOLOGY
COSTS

Determining control technology costs is made difficult by the dearth of commercial applications, fast changing economic trends and uncertain political climate. Nevertheless, for planning purposes we require some estimates of control capital and operating cost to evaluate the relative cost-effectiveness of controls. An appendix to this questionnaire containing cost data derived from current literature, is provided for your reference.

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INSTRUCTIONS: We will require cost information in various formats, depending on the particular control technology considered. Specific instructions are given for each technology. In all cases, give low and high estimates of the appropriate cost items. Estimates should reflect the cost differential directly attributable to control implementation. For instance, the capital cost of a new boiler with combustion modifications for NO_x control should be the increase in boiler cost due to the modifications.

Where capital costs are requested, include in your estimate, the cost of design engineering. Annual costs should include maintenance, energy and monitoring costs, taxes and insurance. Do not include annualized capital cost in the operating cost.

State costs in 1977 dollars. If this is not possible, state the base period for which your estimates are given.

You are encouraged to explain the basis of your estimates, as necessary, in the Comments column.

FLUE GAS DESULFURIZATION COSTS¹

SOURCE:
INDUSTRIAL BOILER - WATERWALL

UTILITY BOILER

PROCESS	EFFICIENCY ²	% EMISSIONS REDUCED ³	INDUSTRIAL BOILER - WATERWALL				UTILITY BOILER						LEVEL OF FAMILIARITY ⁴	COMMENTS ⁵
			OIL		COAL		< 200	200-400	400-800	800-1000	800-1000	900-1000		
			RETOFIT	NEW	RETOFIT	NEW	OIL	OIL	OIL	OIL	OIL	COAL		
LIME STONE	50%	C												
		O												
	70%	C					115-215	70-115	55-110	50-150	35-115	50-120		
		O					3.7	3.6	3.5	3.4	2.7	3.2		
	90%	C					115-220	70-115	55-110	50-150	35-120	50-130		
		O					4.0	3.9-4.8	3.3-5.6	3.5	3.5	3.5		
LIME	50%	C												
		O												
	70%	C					120-210	135-180	125-145	115-145	80-110	85-115		
		O					3.9	3.8	3.7	3.6	2.9	3.4		
	90%	C					180-225	140-190	135-175	120-155	85-120	90-125		
		O					4.2	4.1	4.0	3.9	3.4	3.7		
MAGNESIA	50%	C												
		O												
	70%	C												
		O												
	90%	C												
		O												
SODIUM	50%	C												
		O												
	70%	C					150-210	150-210	150-210	150-210	125-180	125-170		
		O					1.8-8.5	1.8-8.0	1.8-7.5	1.8-7.0	1.6-6.5	1.6-7.0		
	90%	C					210-330	220-210	190-260	180-230	140-190	175-200		
		O					1.0	9.5	9.0	9.0	8.5	8.0		
CATALYTIC OXIDATION	50%	C												
		O												
	70%	C												
		O												
	90%	C												
		O												

1) STATE CAPITAL COST IN \$/KW; OPERATING IN MILLS/KWH; DO NOT INCLUDE ANNUAL CAPITAL IN OPERATING COST
 2) % OF EMISSIONS REDUCTION
 3) C-CAPITAL O-OPERATING
 4) 1-VERY 2-MODERATELY 3-UNFAMILIAR
 5) USE THE BACK OF THIS PAGE FOR ADDITIONAL COMMENTS

COMBUSTION MODIFICATION COSTS¹

SOURCE UTILITY BOILERS

CONTROL	EFFICIENCY ²	STATUS	COST ³	MW						LEVEL OF FAMILIARITY ⁴	COMMENTS ⁵		
				< 200		200-400		400-800				800-1000	
				FUEL	STATUS	FUEL	STATUS	FUEL	STATUS			FUEL	STATUS
LOW EXCESS AIR	30%	C		.53	.33	.16	.21	.12			1974 costs from EPA.		
		O											
	50%	C											
		O											
	70%	C											
		O											
STAGED COMBUSTION	30%	C											
		O											
	50%	C											
		O											
	70%	C											
		O											
FLUE GAS RECIRCULATION + staged combustion	30%	C		8.7-11.8		8.5					1975 costs from PG&E average = \$10/kW		
		O											
	50%	C											
		O											
	70%	C											
		O											
REDUCED AIR PREHEAT	30%	C											
		O											
	50%	C											
		O											
	70%	C											
		O											
BURNER DESIGN MODIFICATIONS	30%	C											
		O											
	50%	C											
		O											
	70%	C											
		O											

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1) GIVE CAPITAL COSTS IN \$/KW, OPERATING COST IN MILLS/KWH; DO NOT INCLUDE ANNUALIZED CAPITAL IN OPERATING COST.
 2) % EMISSIONS REDUCTION
 3) C - CAPITAL O - OPERATING
 4) 1 - VERY 2 - MODERATELY 3 - UNFAMILIAR
 5) USE THE BACK OF THIS PAGE FOR ADDITIONAL COMMENTS

SOURCE

COMBUSTION MODIFICATION COSTS

FUEL	CONTROL	GAS		REFINERY GAS		REFINERY HEATER		WATERGAS BOILER		WATERGAS BOILER - WASTE		LEVEL OF PLANTIVITY	COMMENTS
		CAPITAL	OPERATING	RESIDUAL	COKE	RESIDUAL	COAL	RESIDUAL	COAL	RESIDUAL	COAL		
LOW EXCESS AIR	CAPITAL (000's)	5-8	15-20	20-30	25-35	5-8	20-30	25-35					NEW
	OPERATING (000's)	2-4	2-10	2-10	2-10	2-4	2-20	2-20					
	LIFE	4-6	10-15	10-15	20-30	4-6	10-15	20-30					NEW
STAGED COMBUSTION	CAPITAL (000's)	8-12	20-30	30-50	35-55	8-12	20-50	35-55					REINFORCE
	OPERATING (000's)												
	LIFE												
FLUE GAS RECIRCULATION	CAPITAL (000's)	5-10	30-50	30-50	30-50	5-10	30-50	30-50					NEW
	OPERATING	30-50	70-100	70-100	70-100	30-50	70-100	70-100					REINFORCE
	LIFE												
REDUCED AIR PREHEAT	CAPITAL (000's)		5-10	5-10	5-10	NA	5-10	5-10					NEW
	OPERATING		10-20	10-20	10-20	NA	10-20	10-20					REINFORCE
	LIFE												
BURNER DESIGN MODIFICATIONS	CAPITAL (000's)		10-15	10-15	20-30	NA	10-15	20-30					MINOR
	OPERATING		60-100	60-100	80-120	NA	60-100	80-120					MAJOR
	LIFE												

1) DO NOT INCLUDE ANNUALIZED CAPITAL COST IN OPERATING COST
 2) PREPARE COST ESTIMATES FOR NEW UNITS. INDICATE IN THE COMMENTS COLUMN THE DIFFERENTIAL IN COST (EG PERCENT OF STATED COST) WHICH WOULD BE REQUIRED FOR REDUCTION OF EXISTING UNITS.
 3) 1 - VERY 2 - MODERATELY 3 - UNFAMILIAR
 4) STATE THE COMMENTS EFFICIENTLY IN THE COMMENTS SECTION

FUEL MODIFICATION COSTS

CONTROL	\$ MMBTU	1 2 3 FAMILIARITY	COMMENTS ^{*2}
DESULFURIZATION OF PETROLEUM			
• To .25 % S	\$.25-.61		
• To .1 % S	\$.25-.68		
ALTERNATE CLEAN FUELS			
LOW MED BTU GAS	\$ 5. +		for Bay Area, assumes stripped coal
• SYNTHETIC OIL FROM COAL	\$.50		"
• DESULFURIZED COAL			
DENITRIFIED FUEL	\$ 2.5		
FUEL ADDITIVES (FOR NOX CONTROL)			

* 1-VERY
2-MODERATELY
3-UNFAMILIAR

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**Attachment B - List of Technology Workshop Participants
July 19, 1977**

Alan Goodley	California Air Resources Board
Ron Friesen	California Air Resources Board
Don Bartz	ESB, Incorporated
Don Christensen	PG & E
Robert Hosemann	PG & E
James Quinn	PG & E
Roger Staha	PG & E
Herb Johnson	Bay Area Air Pollution Control District
James Tomich	Bay Area Air Pollution Control District
Don Teixeira	Electric Power Research Institute
Bill Loscutoff	California Air Resources Board
Gary Leach	California Air Resources Board
Eugene Leong	Association of Bay Area Governments
Ron Wada	Association of Bay Area Governments
Irene Kan	Association of Bay Area Governments



Association of Bay Area Governments

Hotel Claremont • Berkeley, California 94705 • (415) 841-8730

May 26, 1978

Mr. James A. Walker, Executive Director
Energy Resources Conservation and
Development Commission
1111 Howe Avenue
Sacramento, California 95825

Dear Mr. Walker:

Thank you for the opportunity to comment regarding the Fossil I and II Project. The following comments are those of staff and, except where noted, should not be construed as an official ABAG policy position either in favor of or in opposition to the proposed project. In response to your letter dated April 21, 1978, we have enclosed with this letter preliminary comments to provide your staff with a timely response and to elicit some feedback from the Energy Commission on which areas of our review are of greatest interest.

Review Responsibility of ABAG

Although the Association of Bay Area Governments does not grant permits, the Association is the designated lead agency for air quality, water quality, solid waste management and industrial siting planning in the Bay Area. In partial satisfaction of these responsibilities ABAG has prepared a long-range integrated Environmental Management Plan for the region which includes the Montezuma Hill Site identified in the Fossil I and II Notice of Intent (our review will be restricted to this site). Also, ABAG has prepared geographically disaggregated long-range projections of population, housing, employment and land use for the region. Our review of the Fossil I and II Project focusses on conformance or non-conformance with our work in these two areas. We note additionally that should the project entail any requests for Federal expenditures under designated programs of OMB Circular A-95, ABAG, as an Areawide Clearinghouse would have the authority to review the project and to ascertain whether it duplicates unnecessarily federal spending and whether it is consistent or inconsistent with regional policies.

The level of detail of information presented in the Fossil I and II NOI is in many instances insufficient to form a basis of a detailed review of consistency with the Environmental Management Plan. Thus, in certain areas where the NOI is not specific we indicate a preferred direction. Our later, official comments will expand the review herein to consider simultaneously the Pittsburg 6&9 projects since many of the same issues

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Representing City and County Governments in the San Francisco Bay Area

are present with these projects. Should any questions arise concerning these comments attached please do not hesitate to contact Dr. Ronald Y. Mada, ABAG Energy Program Manager.

Sincerely,

A handwritten signature in black ink that reads "Charles Q. Forester" with a stylized flourish at the end.

Charles Q. Forester
Director of Plan Implementation

PRELIMINARY COMMENTS ON P.G. & E.'s FOSSIL I AND II PROJECT

Air Quality Considerations

With respect to air quality in the San Francisco Bay Area, P.G. & E. has indicated that the proposed coal-fired facility will conform to all existing air pollutant emission regulations except one: The New Source Review Rule adopted for the nine-county Bay Area by the California Air Resources Board in December 1977. The analyses conducted in support of the Bay Area Air Quality Maintenance Plan indicate two things: First, that hydrocarbon emissions should be minimized from all possible sources, and second that additional NOX emissions from projected new sources would not adversely effect oxidant levels in the region. The New Source Review Rule with emission offset (for hydrocarbons) was identified in the plan and approved as being essential to the attainment and maintenance of the Federal oxidant standard in the region. Thus, in our view, it is essential that appropriate hydrocarbon emission offsets be identified and documented as part of the approval process for the facility. While P.G. & E. acknowledges the emission offset requirements of the regulations, no specific offsets are identified in the NOI for review. Additionally, the New Source Review Rule requires that new sources apply "best available controlled technology". While the emission control technology proposed by P.G. & E. is probably the most reliable and effective, commercially proven technology available today, substantially more effective technologies currently being demonstrated elsewhere could be available for use with the proposed facility. If necessary, a delay in the start-up schedule to accommodate the more advanced control technology should be considered.

Finally, with respect to SO₂ emissions, the Bay Area is classified as Class II area for SO₂ under the Prevention Of Significant Deterioration provisions of the Clean Air Act. Preliminary analyses appear to indicate that as proposed, Fossil I and II would consume roughly 80% of the allowable incremental emissions in the vicinity of the plant. This means that only 20% will remain for other potential sources, thereby significantly reducing the possibilities for certain new industry as well as cogeneration. In the interest of maximizing industrial siting options in the Bay Area while still meeting cleaner air goals, any improvement in SO₂ control efficiency would be of substantial benefit.

Water Considerations

The proposed plant will withdraw 45 m.g.d. of river water as cooling system make-up returning about 30 m.g.d. after use. Because this 15 m.g.d. is consumed it is no longer available for downstream use. We would urge a thorough evaluation of alternative sources of water that would avoid any depletion of river flow. A regional study of wastewater reclamation in the Bay Area is about to commence. Reclaimed wastewater from the Bay Area is a desirable water source because if used at the power plant it would both provide cooling water and augment river flows.

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Solid Waste Considerations

The proposed project will produce large quantities of fly ash from the baghouse, bottom ash from the boiler and sludge from the desulfurization equipment. Three alternatives are being considered by the applicant for disposing of the ash and sludge. They are: 1) beneficial reuse, 2) on-site disposal and 3) off-site disposal. If land disposal were used, the ash and sludge would be mixed together prior to disposal. At present there are too few data on the characteristics of the mixed sludge and ash complex. Therefore, further studies should be conducted in order to determine the design criteria for land disposal. In addition, in order to minimize any adverse environmental impacts, such design criteria should also meet the requirements of the Federal Resource Conservation and Recovery Act of 1976, as well as the requirements of the State Water Resources Control Board and the Regional Water Quality Control Board.

The Fossil I and II project suggest the use of refuse-derived fuel as an alternative fuel source. ABAG's draft Environmental Management Plan includes the recommended action that resource recovery projects be reviewed to ensure consistency with county and regional solid waste plans and other environmental goals and standards. We would urge that additional analysis for the project indicate the degree to which the use of refuse-derived fuel is consistent with the county solid waste management plan.

**REPORT ON THE CONFERENCE ON
"THE USE OF COAL IN CALIFORNIA"**

Date: May 9-11, 1978

Submitted by: People for an Energy Policy (PEP)

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Report on the Conference on "The Use of Coal in California"

1. PARTICIPANT'S REACTION

1.1 INTRODUCTION

On May 9th through 11th, 1978, the Jet Propulsion Laboratory organized a conference on coal use for California, co-sponsored by the Federal Department of Energy and the California Energy Commission in Pasadena, California. This was a first in an effort to explore the practicality of the use of coal for California's future energy needs. This conference was unique in that it provided the opportunity for a group with diverse viewpoints to get together and exchange information.

Represented were Industry, Federal and State Governments, Universities, and Public Interest Groups. Thorough discussions ensued for three days on the need for coal in California's energy mix. Technical, environmental and economic issues, surrounding the use of coal as an energy source for California were discussed.

1.2 CONFERENCE REACTION

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Governor Jerry Brown, Jr. addressed the opening session May 9th. He encouraged California to take a leadership role in developing the right energy mix. He set the scene for consideration of the use of coal in California.

The conference created a promising format for California's citizens. It established a forum whereby leading conservationists and executives from coal mining and coal consuming industries explored common grounds on numerous issues. Overall the conference was well organized and ran smoothly. This was a successful beginning in communicating issues on the use of coal for California.

The conference showed the need to introduce coal into our energy mix. The need was apparent to study diverse options to supply California's growing need for energy. We must include conservation, hydroelectric, natural gas, solar, oil, geothermal, coal, and nuclear. The availability of these energy resources can create the "balanced energy mix". More development and expanded use of conservation will be needed, but with gas and oil becoming increasingly expensive and in short supply, other options will be necessary to meet the State's near term requirements. The State must surely recognize the need for both coal and nuclear. Here we are with a virtual nuclear moratorium in the State such that coal becomes a likely candidate for a future energy source in California. The stage is set for controversy. Intervenor's will address the concerns and all of California will be benefited from these discussions.

As a result of this coal conference the forum to discuss coal's use in California has been created. We should expect this forum to evolve into a team which will include a broad section of the attendees at the conference to assure continuity. This team should include members of all the diverse groups represented to ensure a comprehensive study and the necessary leadership role to stimulate interest, initiate studies, and pull together all issues for consideration in determining the role for the use of coal for Californians.

2. NEED AND USE FOR COAL IN CALIFORNIA

2.1 EXPANDING ENERGY NEEDS

California has a dynamic and expanding economy. California must continue to evaluate its social and economic future in order to identify and assure the necessary ingredients are available to support plans for economic growth. One vital ingredient is energy. The amount of available energy and cost of such energy will have a significant impact on the future life style in California.

The popular and most widely accepted plans for California are focused on an expanding population and increasing economic growth. The population is expected to increase from an influx of people moving to California in search of the "good life" and from the maturing of our present population. This maturing alone will significantly increase the number of households and the work force. Adequate plans should assure sufficient energy to provide for these expanding needs. New families, whatever the source, will require housing, transportation, jobs and civil services. In providing for new families, we must continue to attract selected industry and new business to provide jobs for youth and maintain our present standard of living. At the same time we must strive to increase the standard of living of the economically disadvantaged.

2.2 AVAILABILITY/USES FOR ENERGY OPTIONS

A conservative estimate of the forecasted energy growth rate to provide for the social and economic plans of California is a 4.5 per cent increase per year. Most of the energy needs of California are presently provided by hydro-electric, gas and oil. The oil embargo of 1973 was a clear sign that large oil supplies are not always reliable and that the supply is limited. Other uses of

gas and oil such as for mobile energy sources for planes and tractors, the plastics industry, medicines, and fertilizers emphasize the need for conservation of these resources and a diversity of energy options. We cannot depend on gas and oil meeting our future energy needs economically.

The recent drought in California (1975-1978) was another sign that hydroelectric energy will not always be dependable. In addition, future expansion of this resource is doubtful. We are using about all the hydro power available in the State without significant damage to our waterways and water quality. Consequently we must look to other options to meet California's projected needs.

Some of these options include solar, wind, nuclear fusion, nuclear fission, geothermal, coal and biomass. Solar power and conservation are presently being actively promoted in California. Conservation is effective in reducing the projected forecast, but voluntary conservation is very uncertain and therefore unreliable. Solar is presently being used for heating but here again the degree of use is uncertain and unreliable due to the state of technology and cost. Both solar and conservation will continue to play an important role in California's options, but their contribution over the next ten to twenty years will only be a few per cent of the total energy used. Geothermal and biomass power also play important, although very limited, roles in the State's energy needs. California is fortunate in having a few of the limited sites for geothermal, but not enough to contribute significantly to projected needs. Nuclear fusion, breeder reactors, and wind power have a number of technological problems to overcome to become a viable source in the next thirty years.

2.3 SHORT TERM ENERGY SOURCES

The most promising alternatives for new energy generation in the next ten to twenty years are coal and nuclear fission. Both of these options should be considered for California. Here we will only consider the possible uses of coal in California.

2.4 COAL UTILIZATION

Coal can be used both directly or indirectly as a fuel to provide energy. Directly it can be used for heating, electric power production, and process steam for industrial use. Indirectly coal can be transformed into clean gaseous or liquid fuels. Coal constitutes about 60 per cent of our remaining fossil fuel reserve in the United States. It presently supplies 45 per cent of our Nation's energy needs but only about 6 per cent of California's energy. Early acceptance and development of the coal option in California could eliminate future energy shortages for mass transportation, food processing and agriculture, paper industry, petroleum industry, steel industry, and the cement industry. Continued growth of the automobile use requires large quantities of energy to produce the fuel the automobile uses, to produce the steel for fabrication, and to produce the cement for the roads on which it travels. The social and economic well being of California could very well depend on the use of coal as one of our energy options.

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3. IMPEDIMENTS TO THE USE OF COAL

All energy options that we employ or plan to employ have some adverse effects as viewed by various groups. The more we know about a given technology, the more we recognize these negative impacts associated with each option. Hydroelectric impacts the waterways with dams which disturb the natural environment. Gas and oil produce hydrocarbons and carbon dioxide which are released to the environment. Solar collectors require land use and are considered an eye-sore by many. Nuclear produces radioactive and thermal wastes which must be managed.

The negative impacts of coal are fairly well known and act as impediments to its use. Coal is commonly regarded as a "dirty" fuel because of the pollutants generated by its use. These stack gas pollutants and the residual ash must be managed. These factors and other impediments are covered in the following discussion.

3.1 ENVIRONMENTAL CONSIDERATIONS

Environmental considerations have been assuming a major role in determining the use of the various energy options. The establishment of the Environmental Protection Agency (EPA) and the evolution of the controls which they are mandating has cast a shadow on the generation of electrical energy with coal. To avoid detrimental effects on the environment and meet the SO_x , NO_x , and particulate emission standards of the Clean Air Act, coal plants require stack gas cleanup systems which challenge the state of the art. Technical problems combine with high costs of installation and operation to make the use of coal in new installations less attractive. The CO_2 "greenhouse" effect is of concern. Much more research is needed before a commitment to burn large quantities of coal is made.

Another environmental consideration is the disposal of the solid waste generated by burning coal. Adequate plans must be formulated to minimize the impact of this concern.

3.2 TRANSPORTATION

The uninterrupted movement of a supply of coal to power plants presents a major challenge. The unit coal trains could not be adequately handled on California tracks without a major upgrading effort. Railroad bed upgrading should be accomplished with the goal of minimizing traffic problems at automobile intersections. The societal considerations of noise, vibration, and coal dust must also be minimized in the upgrading process.

The transportation of coal by slurry pipeline is particularly attractive, but must consider the availability of water at the source and the interstate policies involved. The neighboring states which can provide coal to California were found by the Water Resource Council Final Task Report to be in areas with critical water related energy problems. It is not likely that they will want to export a scarce resource. To make the slurry pipeline feasible, it might require a parallel water return pipeline.

3.3 COOPERATION OF NEIGHBORING STATES

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It appears that the neighboring states would provide coal to California as long as they have a surplus over their needs but their willingness to absorb any of the coal generated problems is questionable. The continued siting of coal fired generating plants in other states with export of their electrical power output to California is becoming less attractive to the involved states. These effects on surrounding states must be considered in any coal utilization plan.

3.4 LABOR CONSIDERATIONS

The reliability of coal mining and railroad unions must be considered. Labor agreements and contracts should be structured to maximize the reliability of the continuous supply of coal to generating plants.

3.5 STATE REGULATORY CONSIDERATIONS

Certain events such as the discontinuing of plans for the Dow Chemical Plant and the Condor Nuclear Plant have contributed to the future of the

California is discouraging industrial growth. There is no question that the regulatory environment contributed to the demise of the projects. The Governor has expended a lot of effort to assure everyone that California is not anti-business, but this concern must be addressed by regulatory actions.

The California Energy Commission is being diligent in their exploration of all energy alternatives. The concern held by FEP is that their enthusiasm for solar, geothermal, wind, and other developing options might preclude the proper encouragement of those options best suited to provide our growing energy near term needs. Coal and nuclear power are seen as necessary and presently useable options which can carry our State into the Twenty-First Century. The Energy Commission should realistically assess all options as to their ability to meet our power requirements and provide a balanced program to meet our increasing needs.

3.6 CAPITAL INVESTMENT CONSIDERATIONS

Power plant capital costs for new plants are running in the neighborhood of \$1000/KWE. This puts the cost at \$1 billion for a 1,000 MWE plant. Raising this kind of capital over an extended construction period of 8 to 12 years becomes a monumental task. In order for a lender to make this kind of commitment he wants a stable borrower and the assurance that the project will become operational to return money on the investment.

In order for the utility to have a good credit rating, i.e. appear stable, it is necessary for them to have a sufficient return on their investment and operating costs. The Public Utility Commission is a key determinant of the utilities' ability to finance projects. Rate relief must be given due consideration in order to ensure the viability of utility borrowing.

An additional consideration is the willingness of Banks to make loans on a long term project which has to be constructed in an adverse socio-political environment. If there is doubt that the plant will ever become operational, loans

will not come readily. The present holding pattern on Diablo Canyon and the recent cancellation of the Sande Desert Plant cast a real concern on the viability of nuclear projects. New commitments to coal must be made in an environment which parallels that of these nuclear projects. This environment must be improved to make these options work.

3.7 TECHNICAL DEVELOPMENTS

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Nationally coal research and development is receiving a great deal of attention. There are many options for the burning of coal which are being pursued. Each of these has potential in its own right, but must overcome certain obstacles.

ATMOSPHERIC FLUIDIZED BED (AFB)

The AFB shows a great deal of potential for burning high sulfur coal and controlling the stack releases. Major obstacles it faces are the distribution of the coal to the reactor for even firing and competition from the Pressurized Fluidized Bed advocates. Further development on the AFB is required and it is estimated that it would be the late 1980's at the earliest before there would be an AFB in commercial operation.

COAL LIQUIFICATION

Coal liquification is having developmental problems and appears to be a longer range option. Commercial operation is estimated to be out beyond 1995.

COAL GASIFICATION

Coal gasification appears to be an easier alternative to develop than coal liquification. It's major obstacle appears to be the complex, expensive gas cleanup system required. This has been estimated to be in commercial operation by 1993 at the earliest.

SOLVENT REFINED COAL (SRC)

SRC does not appear to be as attractive as a developmental alternate. Problems with the high ash content continue.

CONVENTIONAL FURNACES/STACK GAS CLEANUP

Conventional furnaces are a proven state of the art and stack gas cleanup systems are also operational. The high cost of stack gas cleanup still has everyone searching for a better way. The goal of keeping coal gas emissions to the level of low sulfur oil emissions is a difficult task. Various alternatives of flue gas desulfurization are being explored. The particulate fly ash can be handled by electrostatic precipitators or bag houses. The bag house show some real benefits.

Overall, it appears that conventional furnaces with stack gas cleanup systems have the capability to be employed now to help us meet our energy needs.

4. RECOMMENDATIONS

PEP believes that all sources of energy should be considered for use by California, including coal. The following recommendations are intended to help California use coal to the State's benefit. Some of these recommendations would be applicable to the promotion of other energy sources also.

4.1 GOVERNMENTAL LEADERSHIP

The Governor of the State of California should provide the leadership to create reasonable opportunities to construct privately owned coal energy facilities. The legislature must provide the enabling and supporting legislation. The Governor must take an active part in implementing any of the ensuing recommendations. A common need is for leadership in calling for solutions to problems, rather than roadblocks, as well as clear delineation of the responsibilities of State Agencies involved with energy.

Although more state leadership may be needed in facility location, it is thought best to limit their function to one of review and not initiation of site location decisions.

4.2 ENERGY PLANNING

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California must have a clear and well defined energy plan which considers all the alternate energy sources and their capability to be utilized.

The first step is to define the expected demand for energy in general and coal in particular. In the short-term (on the order of 20 years) existing technology and environmental considerations will probably limit coal to central electricity generating stations and some industrial process heat applications. It is important to accurately forecast the need in terms of quantity and schedule. This is particularly true for coal where extensive supporting facilities are required and long term supply contracts must be made.

4.3 ENVIRONMENTAL STANDARDS

A clear definition of environmental standards which will be applied to

California's utilization of coal must be made.

PEP does not favor relaxation of environmental standards which reasonably protect the health and well being of the citizens of the State. The health problems caused by gaseous and particulate emissions from coal combustion are well established. Current technology must be evaluated to assure reliable energy production and acceptable air standards in the meteorological context of California.

Increased air quality requirements cause increased quantities of solid wastes. Much more thought of safe, permanent storage of this quantity of wastes must be given.

Solutions to these gaseous and solid waste problems may be such an economic penalty that it could be a real limitation to the use of coal in California. It is important that the environmental requirements be clearly defined before embarking on a coal program in California.

4.4 COMPREHENSIVE STATE REVIEW BOARD

A comprehensive State review board representing all State agencies involved with energy facilities should be established to expedite the complex review process. Faster, more thorough review would mean less time either to reject or complete the facility. A shorter time would provide more flexibility in planning as well as reduced overall energy costs.

The recent example of the Dow plant illustrated the problems, exaggerated or not, of dealing with a multiplicity of agencies whose goals are not always consistent. It is recognized that an Energy Facility Review Board would not necessarily have had jurisdiction over the Dow plant.

Although the California energy industry has developed an ability to work with the existing system, coal facilities present new and complex challenges to regulatory practices. There are no major coal facilities in California and therefore no model rules to follow. Simpler regulation may ease the introduction of this energy source into California.

Examples of administrative groups which should be represented on such a review board could include air and water quality, land use, coastal agencies, fish and wildlife, transportation, safety, and local government representatives. This board should be charged with implementing the State energy plan, solving rather than creating problems and suggesting alternatives if proposed plans prove unacceptable.

4.5 ESTABLISH WESTERN AREA RELATIONSHIPS

The Governor should initiate plans to work more closely with neighboring States and encourage a more cooperative Western regional effort. Every effort should be made to recognize and support a feeling of interdependence between neighboring citizens.

For a short while, California will continue to need electricity imported from neighboring States. It may be that limitations in transportation as well as other economic considerations will make it desirable to locate new coal electric generating plants in neighboring States. It seems important to inform our neighbors that these are the true reasons and not just an attempt to export the pollution.

Additionally, the problem of disposal of solid wastes must be considered. As mentioned above, this problem has not been thoroughly studied. Neighboring States may resist receiving these wastes.

In general, a better spirit of cooperation must be sought.

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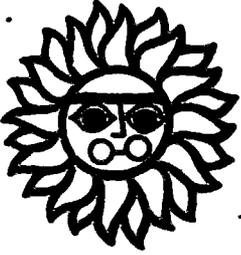
5. SUMMARY

A scenario of continued growth in energy consumption by California is probable. A 4.5 plus per cent increase per year will be required to meet our population and economic growth. Conservation is an immediate, but undependable alternative. Solar, wind, geothermal, biomass, and fusion are promising but unlikely to make a significant contribution to our short term needs. Hydro-electric is pretty well being utilized fully now. Gas, oil, coal, and nuclear appear to be the near term options to meet our projected growth needs.

Gas and oil presently fulfill a large part of California's energy needs and could be utilized to meet our expanding needs if supplies prove dependable and plentiful. The growing recognition of alternative uses of gas and oil, as exemplified by the Shah of Iran's purchase of nuclear power for his country, may make gas and oil too valuable and expensive a resource for our long term use. Thus, coal and nuclear must be considered as alternatives for new energy needs.

The coal conference indicates the potential for lack of leadership and the lack of a cohesive State energy policy which may effectively preclude the use of coal in California. The consequence of this action in conjunction with unavailability of gas and oil could result in an energy shortage that would lead to high cost energy. This would stifle economic growth and put an undue burden on California citizens, especially those on fixed incomes.

To assure the ability of California to meet its energy needs we must continue to promote actions such as the coal conference. We need to develop a sound energy policy with a unified/effective Energy Commission to implement it. We must provide the overall leadership to ensure a reliable, growing and economic supply of energy for California. This is vital to our standard of living and our free enterprise economy.



CITIZEN ACTION

CALIFORNIA CITIZEN ACTION GROUP

NORTHERN CALIFORNIA
909 12th Street
Sacramento, CA 95814
(916) 446-6931

SOUTHERN CALIFORNIA
2315 Westwood Blvd.
Los Angeles, CA 90064
(213) 475-0417

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REACTION TO CONFERENCE ON COAL USE FOR CALIFORNIA HELD IN PASADENA, MAY 9-11, 1978

The California Citizen Action Group, a statewide consumer organization of some 5,000 members which regularly intervenes in policy proceedings before the California Public Utilities Commission and the Energy Resources Conservation and Development Commission, was represented at the Coal Conference in order to stay abreast of developing issues as coal is introduced into California's energy supply system. Citizen Action's involvement in energy issues has traditionally been from the perspective of Californians' economic interests as individual consumers. Issues such as air quality, safety, land use, water availability, and waste disposal have been relevant only insofar as they represent economic costs which must ultimately be borne by California's consumers. Similarly, the cost of energy to commercial and industrial users has been of concern only to the extent that it is reflected in the price of goods and services purchased by individual consumers.

Citizen Action's present interest in coal use is primarily in its application as a fuel source for electrical generation. From the standpoint of state policies, this is the only use of coal for which an institutional framework exists which provides an available forum for citizen group input, and even this participation is circumscribed by the availability of financial resources. The much more decentralized choices which must be made in determining coal's suitability as a boiler fuel do not lend themselves to public intervention in the decisionmaking process, except to the extent that such

usages must conform to air and water quality standards. To some degree, the Public Utilities Commission's recently concluded investigation into natural gas supply policy for the 1978-1990 period, in which Citizen Action participated, might be seen as involving a choice between natural gas and coal for P3, P4, and P5 customers -- but this contrast was never raised as an issue during the nearly 60 days of hearings, and fuel oil was considered throughout the proceedings as virtually the only substitute for natural gas as a boiler fuel.

Even in the limited context of coal use for electrical generation, there is confusion as to precisely what degree of flexibility California energy supply planners will have in the coming decade in choosing between coal- and oil-fired baseload power plants. The uncertain status of the National Energy Plan, and the seemingly broad environmental exemptions from its coal conversion provisions, has contributed to a generalized confusion as to what President Carter's and Secretary Schlesinger's repeated incantations of increased coal usage actually mean for California. It was the failure to address at the very outset this confusion in national policy regarding all usages of coal which, in Citizen Action's view, constituted the greatest shortcoming of the Pasadena conference.

The organizers of the conference should have attempted to establish a policy context for coal usage in California at the opening session. An attempt could have been made to examine the various coal conversion provisions of the National Energy Plan, survey the different exemptions, explain as well as possible other federal policies relating to coal usage, and relate this all to California. Certainly this would have provided a framework for the subsequent examination of technological, institutional, and social issues which Citizen Action saw as the *raison d'etre* for the conference in the first place. Instead, the soporific repetition of one-line beatitudes was substituted for a meaningful discussion of policy. Nowhere was this more prevalent

than in the remarks of Dr. Alec Mills, speaking in place of George Fumich Jr. as the DOE representative in the opening session: "I don't believe the hard path and the soft path are mutually exclusive -- in the words of Bob Thorne, they're mutually dependent." Apart from the heretofore unprecedented conscription of the legendary Mr. Thorne into the ranks of energy philosopher-sorcerers, Dr. Mills' profundity cast little illumination on federal policy with respect to coal. In fact, until disabused of this by the conference organizers, Citizen Action was of the strong suspicion that the disjointed nature of the conference had been staged in order to cast the thoughtful but mundane remarks of Governor Brown and Energy Commission Chairman Richard Maullin in statesmen-like roles.

In its discussion of various policy issues surrounding coal usage, the conference left a good deal to be desired simply in terms of choreography. There seemed to be a minimal amount of coordination between the members of each panel, and the degree of advance preparation appeared to vary considerably from speaker to speaker. Even more troublesome, the assumed level of common knowledge attributed to members of the audience was quite low. The resulting discussion of policy matters was quite elementary, and hardly worth presentation in a conference format. In Citizen Action's view, these problems could have been corrected by a greater effort on the part of the Jet Propulsion Laboratory to focus the discussions. Considerably greater advance communication with panel participants was obviously necessary, and the preparation by each participant of a brief discussion paper which could have been circulated before the conference to all registrants would have been quite helpful. Because of the conspicuous informality which had surrounded the various speakers' preparation, Citizen Action has no way of evaluating whether a shortcoming existed in the actual selection of individual panelists. In the interest of preserving interstate relations with Texas, a vital supplier of natural gas to California, Citizen Action has no comment on the selection of the dinner speaker except to note that a guitar and a Stetson would have

greatly improved his presentation without detracting noticeably from the content of his remarks.

To the extent that the conference was intended to serve a second purpose, the exchange of technical information between various elements of the coal energy delivery system community that are interested in expanded usage in California, Citizen Action has no real basis on which to comment. Whether the information provided by the panelists was of value to the commercial participants is something only they can answer, but from the amount of business cards which changed hands during the coffee breaks it was clear that information exchanges take place at a range of different levels at conferences. While the prevalence of vendors in the audience made it clear from the outset that the conference did not have the innocence of a high school science fair, neither did it take on the crassness of a high technology swap meet. By falling in between, however, the technical information transfer objectives of the conference were unclear -- especially in light of the rather basic level of the subject matter discussed.

In that area which was Citizen Action's main interest in the proceedings, the economics of coal usage, the conference discussions were quite frustrating. The truism that coal use can not be both clean and cheap was invoked by a variety of speakers. Leaving aside the question of whether it can be either, most of the references to cost during the three days were made in the tone of something which someone else would have to deal with. ETSI representative John Lynch best embodied this general attitude: "To put any restrictions on how far we go for our energy, to put any restrictions on what is an economical source of energy, is a mistake we have made and we cannot afford to make that mistake any more ... what we need is a dependable source of energy."

An obliviousness to cost is often typical of those who concern themselves primarily with the technical aspects of energy production, a burden to be overcome rather than a criterion by which to choose. This economic myopia is

usually justified by the boosterism of an oil field wildcatter, or the assertion that there is no choice by a technocratic specialist. Because its orientation is to the supply planning function conducted by public agencies, and because it is neither blessed nor victimized by a specialization in any one particular energy source, the California Citizen Action Group ordinarily finds these assertions quite alien. In fact, Citizen Action's fundamental premise in its intervention in regulatory proceedings is to posit the existence of choice and the relevance of economic cost -- when fully calculated -- as a basis by which to choose. Unsurprisingly, this was not a viewpoint to be found at a gathering of coal junkies.

From those economic aspects of coal usage which were discussed, Citizen Action has cause for small concern. Ignoring the more exotic applications such as liquefaction and gasification, which are likely to be heavily subsidized by the federal government as demonstration projects for the foreseeable future, the reliance on coal combustion as a source for California's electrical supplies is likely to contain several economic risks of enormous magnitude. The first and most obvious is the relationship with the coal producing states, all of which went to great lengths to indicate that California would have to provide remuneration for pollution caused by mining operations. The same was true, but even more so, for any minemouth generation facilities -- although the representatives from producing states indicated that such facilities would likely be precluded altogether because they are tantamount to the politically heinous crime of interbasin water transfer. Even assuming that such water can be made available, this is a substantial cost which California consumers will be expected to bear. Similarly, as Utah representative Reed Searle put it, no slurry pipelines will be built without a water exchange guarantee, which he envisioned as requiring dual pipelines stretching from Utah to California, one carrying coal slurry west and the other carrying clean water east.

A second such risk involves the nature of the coal transportation

system itself. The structure of the conference provided a perversely illuminating exchange on the merits of slurry versus rail transportation. According to slurry advocate John Lynch, slurry costs are about one half of those incurred by rail transport; slurry costs are intrinsically more stable over time because more than half of rail expenses are tied to the cost of labor whereas slurry pipeline costs are almost entirely capital; slurries have economies of scale while rail transport does not; western rail carriers have historically lacked even barge competition and have been able to charge what the traffic will bear; and "railroads cannot be allowed to continue their dictatorial stranglehold over moving the nation's coal." According to Frank Guerin, speaking for the Southern Pacific railroad, SP already owns the largest slurry pipeline in the world, it foresees no problems in providing sufficient rail capacity, "and I suggest you call your stockbroker." As asserted by Mr. Guerin, capital formation will not pose a problem to the coal transport sector "because the advantage to the consumer will support a price sufficient to raise capital."

Apart from the gleeful optimism of one very well-situated company in the coal transport sector, the conference proceedings gave a fleeting glimpse of just how serious capital formation problems may be in promoting expanded coal use for electrical generation. As indicated by Edward Vickers, appearing on behalf of the Bank of America, financing has become an increasingly important variable in coal project development and currently stands in excess of all other costs combined. According to Mr. Vickers, inflation has both increased capital and construction costs while at the same time eroding the borrowing power of the firms involved in coal production. Furthermore, most mining companies -- which had no debt at all in the early 1960's -- are presently carrying debt up to 30-40% of their capitalization, which Mr. Vickers identified as approaching the limit of their creditworthiness under conventional financing. The solution; according to Mr. Vickers, virtually all coal projects in

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California will require some form of cash-flow or project financing. Under such financing, lenders are willing to provide up to 75% of the capital in debt form in exchange first claim to the revenues generated by the project being financed. While this technically takes the financing of a project off of the borrower's regular books and frees the borrower from its debenture/indenture requirements, it nevertheless requires completion and performance guarantees which expose the borrower (and ultimately consumers) to considerable risk. Secondly, to the extent that the equity portion of the project finance is provided by a borrower's normal capital structure (i.e., 30-50% debt), the portion which is derived from debt creates a "double leveraging" of the equity which can result in an exorbitant rate of return on "true equity" upwards of 20%.

Project financing has yet to be extensively used by California utilities, and can not be regarded as a proven financing vehicle by which to bring new energy supply projects on line. The first major scrutiny which the concept has received is CPUC Application No. 57626, in which a joint venture of the Pacific Lighting Corporation and PG&E have applied for a construction permit to build an LNG terminal. There, the problem of double leveraging has been raised by PG&E's financing plans, while Pacific Lighting faces problems of dilution of the value of its common stock because of its decision to finance its portion of the project's equity requirements entirely through sales of stock. Furthermore, the portion of the project which will ultimately be considered equity has climbed from 25% to 34% because of AFUDC, resulting in much higher rate of return requirements.

A further problem in financing coal projects is the coal itself. As described by Milt Lavin, one of the JPL moderators, there is a financial chicken and egg problem where the mine operator won't invest in a new mine (which can take as long to develop as it does to build a new baseload power plant, according to Joseph Vancik of Bituminous Coal Research, Inc.) until

it has a contract with a utility, and a utility won't invest until it has a site for a power plant. Once a contract between the mine operator and the utility is negotiated, some provision must be made for escalation of the contract price. According to Lowell Rush of Ernst & Ernst, this is likely to necessitate the use of a coal adjustment clause similar to those which have wreaked such havoc on the federal regulatory process in the petroleum sector. At a time when federal policy appears to be the indexing of energy prices to the world price of crude oil, it apparently is too much to expect a utility to be able to obtain a long-term contract at a fixed price for the life of the project, with future escalations tied to some non-energy index. However, as Mr. Rush took pains to note, the use of such adjustment clauses can very easily reduce whatever incentive a utility has to get the best price from a supplier and can prove very difficult for regulators to monitor.

In assessing the economic aspects of coal as a source of electricity generation, careful heed must be paid to the uncertainty of cost projections for any electrical generation facilities. The past decade has seen enormous increases in construction and operating costs, as well as an increase in the magnitude of uncertainty surrounding cost projections that is virtually intolerable for planning purposes. In general, however, it is escalations in capital and fuel costs which have represented the most significant sources of uncertainty in cost projections, and there is reason to believe that these escalations may be interdependent over time. Consequently, they may be of less value for comparative purposes than other, more qualitative criteria. In Citizen Action's view, however, it is precisely this inflationary factor which is of greatest relevance in making the comparison between coal and the so-called non-generational alternatives: conservation and solar. As the de facto indexing of all conventional energy prices seems increasingly ever-present, and such cartel-like behavior becomes tentatively embraced by the Carter Administration as a move to stem oil imports, the economic merits of

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the non-generational alternatives should loom large in the eyes of California's energy supply planners.

Although price as an inducement to energy conservation has recently received a measure of respectability among environmentalists and laissez faire economists, analysis of direct household energy consumption in 1976 indicates that energy price increases are highly regressive. As a proportion of before-tax incomes, energy consumption falls dramatically as incomes rise. The poorest 10 percent of all households (a household with an income less than \$3,000 per year) spend 20.2% of their monthly budget on home energy consumption and 9.6% of their budget on gasoline. In contrast, the average household (with an annual income of about \$12,000) spends 3.8% of its income on home energy consumption and 3.6% on gasoline. The richest 10% of all households (with income above \$30,000 per year) spend only 2.0% on home energy consumption and 2.2% on gasoline. As a result, a 30 percent increase in the price of energy will reduce the average household's real income by 2.2%. For the poorest decile, any increase in the price of energy will cause a reduction in real living standards that is 7 times as large as it for the richest decile, or a decline of 8.9% and compared to 1.3%. Similar disparities can be shown for the effect of energy-induced price increases for consumer goods and services. (All figures above are taken from "Distributional Impacts of Carter's Energy Proposals," prepared by Lester Thurow for the Congressional Joint Economic Committee, May, 1977.)

The California Citizen Action Group feels that California's energy supply planners must give greater attention to the economic ramifications of energy technology choice than has been done in the past. While the prevalent concerns raised by the coal conference related to the inflationary impact of such technology choice, there is a growing body of research on the comparative employment potential of different supply options. In Citizen Action's view, these considerations will increasingly tend to favor the non-generational alternatives. As energy supply planners come to recognize that new supply

projects represent the largest societal investments subject to state influence, these investments will be expected to serve more needs than merely securing an adequate number of btu's. It is in this context that the future role of coal in California should -- and will -- be determined.

RESPONSE TO CONFERENCE ON COAL USE IN CALIFORNIA

prepared by

Environmental Improvement Agency
County of San Bernardino

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Disclaimer: The following report was prepared by staff who attended the May 9-11, 1978 Conference on Coal Use in California: it does not necessarily represent County policy. The Board of Supervisors of San Bernardino County neither reviewed nor approved the text.

Report: San Bernardino County's involvement in energy facility siting is directed by JUMP (Joint Utilities Management Plan), the energy element to the General Plan. Adopted in 1975, JUMP delineates County energy goals, policies and programs. The four goals of JUMP are:

- 1) Maximize the beneficial effects and minimize the adverse effects associated with siting major utilities.
- 2) Support energy conservation as well as efforts to minimize peak load demands.
- 3) Encourage the development of alternative energy sources which have a minimum adverse effect on the environment.
- 4) Insure adequate citizen participation and local Government review in energy related matters.

Policy which relate to facility siting and review include:

- 1) The County will consider the location of energy facilities in areas of minimal environmental and community impact as shown on the JUMP Siting Analysis maps. Final local approval will be subject to a detailed submittal of information.
- 2) New major steel tower electrical transmission facilities should be consolidated with existing electrical steel tower transmission facilities except where there are technical or overload constraints or where there are social, aesthetic, significant economic or other overriding concerns. Power line routes consisting only of wooden pole lines are not suitable for major steel tower electrical transmission lines. Existing pipeline corridors are not suitable for electrical transmission lines where there expressed community concerns over visibility or other issues.

- 3) Support undergrounding of transmission lines, and encourage development of the technology to hasten this.
- 4) New pipeline corridors should be consolidated with existing pipeline or electrical transmission corridors except where there are technical or overload constraints or where there are social, aesthetic, significant economic or other overriding concerns.
- 5) Establish local comprehensive review procedures for major energy facilities proposed for this County.
- 6) Establish a system to obtain early notification from state and federal agencies of proposed facilities.
- 7) Consider social, aesthetic, economic, cultural, health and other formally expressed community concerns in reviewing and evaluating proposed energy facilities.

JUMP is a working tool for review of energy facilities, containing siting criteria and twelve computerized Siting Analysis Maps. The siting criteria checklist indicates particular topics of concern to the County that are specific to particular types of energy facilities or common to all types. For instance, the concerns for fossil fuels power plants include specific review criteria under the topics of public health and safety, ecology, meteorology and climatology, transportation, soils and geology, and hydrology.

The Siting Analysis Maps indicate constraints to energy facilities by geographic area. Five categories of constraints, from least potential for adverse effect to prohibited by policy and law, are mapped for the six major categories of energy facilities. The constraint categories are a composite of twenty-one social, cultural and environmental variables.

The use of coal and coal products for electrical generation is specifically addressed in JUMP. As with all alternative fuel sources, the use of coal must be evaluated in terms of cost, availability and environmental effects. Cautions are mentioned regarding coal-fired power plants especially regarding air quality and water supply. Coal gasification and liquefaction are analyzed at state-of-the-art status.

Unlike many jurisdictions, the use of coal is not a academic issue for San Bernardino County. Coal is now being used as a fuel source at four major industrial operations within the County, including Kaiser Steel Company. Southern California Edison Company has announced two coal pilot plants for demonstration and research purposes, one a coal gasification plant and the other a coal-fired plant. Two separate large scale (1500MW) coal-fired power plants

have been proposed , with possible siting in San Bernardino County. Several studies of coal use in California have been prepared. The UCLA Study specifically references Cadiz (in San Bernardino County) as a site that would (except for air quality constraint) be highly desirable.

San Bernardino County realizes that the California Energy Commission has pre-empted local control over the siting of power plants. However, responsible local input is necessary if informed decisions are to be made. Local plans and regulations must be understood. JUMP has been the primary tool used by San Bernardino County to transmit local concerns. However, as JUMP recognizes, a continued understanding state-of-the-art technology is pre-requisite to evaluation of power alternatives. Local government, state government, the utilities and industry must have a common basis of knowledge if meaningful dialogues is to occur. As such, events such as the Coal Conference are valuable.

San Bernardino County attended the Coal Conference with the expectation of expanding our understanding of coal technology, cost, availability, and environmental consequences. The session topics appeared comprehensive, beginning with a general overview of opportunities, need, and basic environmental constraints, and then proceeding into details. The three basic technologies - direct-firing, gasification, and liquefaction - were covered, as well as transportation, air pollution, economics, and regulation. Thus, the major topics were addressed.

But were the topics addressed effectively? Did the components of the Conference weld into a comprehensive whole? It is here that we were not satisfied with the Conference. One participant felt that it was a trade show, with each of the vendors explaining the merits of his product. While this view may be too critical, our reaction as a whole was that the Conference was not critical enough in its examination of coal alternatives.

The technological status of coal alternatives was detailed with good information presented. However, it is our belief that the translation of these technologies to commercial uses is the major concern, in particular, relative to costs and environmental consequences. What are the relative advantages and disadvantages of these alternatives? How do they compare to conventional sources or other alternative technologies? What are the water supply considerations of each? What of air quality? Even the experts lacked understanding of how and where other considerations affected their particular field. We left the Conference with many more questions than answers.

The format of the conference was very formal; the level of information either very technical or very general. The formality inhibited exchange of information between the audience and panel, while at the same time did not permit development of a group discussion between panelists. One inherent problem in achieving the optimum compromise in format was probably the audience. Many individuals came from very technical backgrounds, while others were generalists without detailed prior knowledge. It is always difficult to sat-

isfy anyone when the range of interest and knowledge is highly desperate.

Informal interchange between participants seemed most productive at the dinner meetings. However, a luncheon could have been more effective, with tables organized by topic. (These remarks are not really essential, but included only as helpful suggestions for the "next time").

Any innovative activity such as the Coal Conference seldom escapes severe criticism, much of it beyond the control of its organizers. We believe that the Energy Commission, DOE, and JPL should be commended for their effort in organizing the Conference. In particular, we appreciate the financial support which permitted our attendance at the Conference. Overall, we felt that the Coal Conference was a valuable "first" that needs a "second".

Recommendation

In pre-empting local authority in the siting of power plants, the California Energy Commission assumed responsibilities and obligations to local jurisdictions. Similarly, DOE has obligations to the State of California if use of coal is required by passage of the Coal Conversion Act. DOE and the Energy Commission have resources and capabilities beyond those of local government and should take the lead now in developing a strategy for coal use in California.

California needs a regional energy plan that will draw together existing studies and synthesize the constraints and opportunities for coal use. The plan should include:

- 1) A need assessment relative to the potential for alternative sources, including conservation.
- 2) Identification of potential sources of coal relative to availability.
- 3) Determination of transportation systems and routes for coal.
- 4) Resource use analysis of the alternatives.
- 5) Description of resulting ambient air pollutants based on best available control technology.
- 6) Assessment of changes required in existing stack and ambient air quality rules and potential impact for additional loss of local authority required to site coal.
- 7) Identification of potential sites (general and specific) or criteria for selection.
- 8) Development of a program to fund local government participation throughout the NOI and AFC proceeding, beyond the current limited reimbursement schedule.

If the State continues to preempt local control, there may be an unavoidable backlash. The passage of Proposition 13 has created a strained fiscal situation for all local governments. All

jurisdictions must closely analyze their budgets, retaining only the most productive programs and services. Without regulatory prerogatives, and seeing no beneficial role in the planning and siting process, many local governments may withdraw entirely from energy programs. We do not believe that this would be desirable either for the region or the state. Local concerns need to be articulated, with an understanding of the larger issues and perspectives. We suggest that local government be encouraged (and provided the means to) participate in the drafting of the regional energy plan and to continue its involvement throughout NOI and AFC proceedings.

San Bernardino is now the major receptor for power facilities in Southern California. Recent proposals may result in our being a net exporter for the region. Any determination of benefit to the County from further power facility development must be evaluated in terms of revenue and environmental and social costs. Air quality deterioration, water supply curtailment, and additional transmission lines are very possible impacts, but can not be quantitatively judged at this time.

We recognize that the Energy Commission must consider the energy requirements of Southern California as a region. Therefore, we support the development of short term, small scale demonstration plants that can be used to test the feasibility and impact of large-scale plants.

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**COAL USE FOR CALIFORNIA--
Failing to Address the Issues**

Introduction

This paper is a synthesis of the views and responses of members of the Sierra Club who attended the Conference on Coal Use for California, organized by the Jet Propulsion Laboratory under the sponsorship of the Department of Energy and the California Energy Commission. While this paper represents the views of those attending on behalf of the Club, it is not to be construed as official Sierra Club policy.

The original intent for the Club's participation in the Conference, as described in our response to the CEC contract opportunity notice, was essentially two-fold: to identify those conditions under which coal might be an environmentally acceptable energy source for California; and to define those energy policies that can be directed toward encouraging those coal conversion technologies with acceptable environmental and public health impacts. As we shall argue in this paper, the conference failed to provide substantive guidance on these issues, in part due to inadequate conference design and control, and in part due to misuse of the conference as a forum for proposing policies or technical solutions that remained unchallenged during the conference, but about which there has been much dispute elsewhere.

Defining the Problem

California currently uses less than four percent of its primary energy as coal, mostly as fuel for out-of-state electrical generation and a small proportion used directly for in-state industrial purposes (steel and cement production). However, the thrust of National Energy Policy proposals and present planning by utilities in California (including

the California Department of Water Resources) will increase the use of coal for California. Since many of the major environmental problems of the coal fuel cycle are widely recognized, at least in principle, California is in a position to adopt policies and/or technologies that are designed to minimize these adverse effects prior to any major expansion in the use of coal.

In our view, there are a number of interlocking issues that will affect energy policy for California. Foremost among these is the clear need to proceed with programs to protect and enhance environmental quality in California. Implementation plans for preserving clean air or for improvement of air quality in non-attainment areas should remain as a priority. If coal is to be utilized as a fuel for California, what technologies are presently or potentially available that will avoid conflicts with air quality or other environmental standards? Can such technologies be identified and encouraged in a timely fashion in order that they might be available for use before commitments are made to less desirable technologies? A major issue underlying such choices is the demand for coal, which in turn is affected by other California energy policies. To what extent are or will other alternative fuels be available, and to what extent will demand reduction through conservation and increased end-use efficiencies reduce the need for coal? Finally, while California has no major coal reserves, the extractive impacts, including mine safety and reclamation, must be factored into California coal policy.

Conference Results: a critique

While it is probably unreasonable to expect a single conference

to address a number of the outstanding conflicts regarding the expanded use of coal for California, the concerned citizen interested in policies for the use of coal must surely have found a bewildering array of conflicting information presented at the conference. Much of the time at the conference was devoted to descriptions of coal utilization technologies separated entirely from discussions of environmental impacts and economic costs. Yet these issues are key determinants in the choice of technologies to be used. Governor Brown emphasized this point in his opening remarks, stating that it is official state policy to bring about the use of technologies that are socially and environmentally compatible.

While several coal utilization technologies appeared to be more attractive environmentally, their availability and costs were less well-defined. In addition, at least in the case of the discussion of fluidized bed technologies, the discussion ignored most of the criticisms regarding the technology. In the case of fluidized bed combustion, it appears that the European experience is considerably more advanced, at least with regard to more complete carbon combustion and reduction of particulate emissions (cf. extensive discussion in hearing record of the Joint Hearing of the Select Committee on Small Business and the Committee on Interior and Insular Affairs, United States Senate, on Alternative Long-Range Energy Strategies, Dec. 1976). Hence, one is still left in a quandry with regard to the establishment of energy policies that emphasize or encourage those technologies with minimal environmental impact.

Overall, much of the discussion of technologies at the Conference provided either inadequate or inappropriate data for the purposes of formulation of state policy. In fact, one had more of a sense that many of the speakers were selling their particular technology or program, and weren't interested in providing input for policy-making. This is less a problem of conference design and more a problem of not understanding the purpose of the conference (i.e., discussion of energy policy relating to coal use in California).

While some of the discussions were characterized by a lack of candor in presenting information on problems associated with a technology (e.g. the fluidized bed discussion), several talks seemed oblivious to the environmental impacts associated with the particular project. The presentations regarding the WESCO gasification project did not discuss one of the main environmental problems, water availability. In fact, depending upon the type of coal used, high BTU gasification is as water intensive as generation of electricity per unit of output energy. The consumptive use of water in the Western states east of California for energy conversion for export to California is politically (and environmentally) untenable in those states, as emphasized by the views expressed during the panel discussion by representatives from neighboring states. Similarly, the contrast between these views and the discussion of transport of coal by slurry pipeline also emphasized water availability as a key issue.

The discussion of transport of coal by slurry was also remarkable in its omission of economic comparisons to alternative transportation modes. Slurry pipelines appear to be economically competitive only

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for large ton-mile shipments (i.e. large quantities or long distances or both), in which case the water availability problem becomes an even greater constraint.

One of the most important issues that must be confronted by plans for expanded coal use in California is the issue of air quality. The present status of air quality in California can be characterized as being non-attainment for both oxidant and particulates over most of the state. It is unfortunate that discussion of environmental effects of coal use (session 3) did not follow the later sessions on technologies. One might have been able to compare the stated emissions and air quality impacts of a given technology with the regulatory standards, both emission standards and the requirements of the state implementation plan. It is interesting to note, for example, that it appears that emissions attributed to SRC I (solvent refined coal--1) will not meet the expected New-Source-Performance-Standards revisions.

Many air quality issues remain unresolved, and the present regulatory environment is clearly a dynamic process. In addition, one has every expectation that this process will continue to evolve, as the environmental and public health impacts of various pollutants are better understood. This situation has an important impact upon the choice of technology; those that are more adaptable to regulatory changes should be environmentally preferable. This technological flexibility is important in another respect as well. It appears that a small number of facilities with significant emissions might well use up the available pollution increments (in attainment areas) or the emission trade-offs in the case of non-attainment areas. Hence future expansion of similar facilities

or the siting of facilities with competing emissions would effectively be blocked, with attendant economic effects.

Overall, the conference failed to examine the elements necessary for the discussion and formulation of policies for coal use for California. To a large extent, such policy discussions depend upon close examination of detailed information. The conference was unable to elicit such information.

California Coal Policy Development--some suggestions

In our critique of the Coal Conference, we have pointed out those areas we believe to be crucial to coal policy considerations, and the failure of the conference to address them. We are not able, at this time, to suggest a structure for a forum for public discussion of coal policies, except to propose that the planned series of follow-up workshops be postponed, and that a series of policy papers be drafted for circulation to conference attendees and other interested persons. The purpose of these draft papers would be to identify, in some detail, the issues confronting expanded coal use for California, proposed solutions (if any), and a comparison of the perceived costs and benefits. Such discussion papers should include an assessment of the demand for coal, since policy options will depend, in part, upon the rate and quantity of coal use.

The present 'interim' energy strategy adopted by the California Energy Commission outlines the principles upon which coal policy discussions should be based. The Commission notes, in Volume 1 of the 1977 Biennial Report, that "the central problem of energy policy is uncertainty about levels of demand, about costs and availability of energy resources and technologies, and about the effects of energy use on the local and global environment." (p. 98). These basic principles include diversity and

flexibility of energy sources, emphasizing the value of projects which are flexible in terms of size and scale of operation, and which may be easily modified to adapt to future technological advances or regulatory requirements. In addition to these principles, there are several other fundamentals we believe to be intrinsic to the development of a coal policy compatible with environmental goals. Coal utilization projects or technologies which hinder the State's progress toward compliance with the Clean Air Act and its amendments should be avoided, nor should special exemptions from State air quality regulations be granted for such projects. We also believe that coal is best used as an interim or 'bridge' fuel (if at all) until such time as technologies utilizing renewable resources are fully implemented and supply future California energy requirements. Hence development and utilization of coal technologies should not supplant programs to develop other, more environmentally compatible energy resources, including conservation and increased end-use efficiencies.

With its present minimal dependence upon coal, California is in a position to formulate and adopt policies for the use of coal that incorporate present and future environmental goals, and are responsive to future needs of society. However, such policy discussions must be initiated early and involve a broad spectrum of the public and technical communities in order to avoid discovering belatedly, that past policy decisions are not compatible with present environmental and social goals.